Precise and Reliable Time Distribution in the Power Transmission System

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ABSTRACT OF THE MASTER'S THESIS

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This master's thesis is about time distribution that supports substation applications needed for power transmission. The work was done for the Telecommunication department of Finland's power transmission system operator Fingrid Oyj. This thesis answers to the following question: What is the need for accurate and synchronized time in power substations and how it will be delivered?
Fingrid's telecommunication network supports the power transmission grid and its operation. Telecommunication network can distribute time to power substations for the applications that need synchronized and accurate time. Current telecommunication equipment used in Fingrid is getting old and new techniques are planned to be implemented. When Fingrid is acquiring new communication equipment, they need to set requirements on the capability to distribute time. This thesis is an initial effort to investigate time distribution requirements for Fingrid's needs. This thesis aids Fingrid Telecommunication department to define requirements for time distribution.
For this thesis, I met with multiple Fingrid professionals, telecommunication device suppliers and time distribution researchers. This thesis answers to its research questions by means of a literature review and interviews.

Keywords: Time, Time Distribution, Power System, PTP, Time Accuracy

AALTO-YLIOPISTO
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Tämä diplomityö käsittelee ajansiirron vaikutusta sähköasemasovellusten toimintaan. Työ tehtiin Suomen kantaverkkoyhtiö Fingrid Oyj:n tietoliikenneyksikölle. Fingridin tietoliikenneverkko on osa kantaverkkoa ja mahdollistaa sähköjärjestelmän toiminteita. Tietoliikenneverkon yksi palvelu on synkronoidun ajan siirtäminen sähköasemille. Nykyinen tietoliikennetekniikka on vanhenemassa ja uutta laitteistoa suunnitellaan hankittavaksi ja testattavaksi. Tämän diplomityön tarkoitus on selvittää mikä on järkevä tapa toteuttaa ajan siirto ja kuinka tarkkaa sen pitää olla. Työ auttaa tietoliikenneyksikköä hankinnan vaatimusmäärittelyssä ajansiirron osalta.
Työtä varten on tavattu monia Fingridin asiantuntijoita, tietoliikennelaitetoimittajia sekä ajansiirron asiantuntijoita. Työ vastaa tutkimuskysymykseen kirjallisuuskatsauksen ja haastattelujen perusteella.

Avainsanat: Aika, Ajan siirto, Kantaverkko, PTP, Aikavirhe

Preface

This thesis was carried out at the transmission system operator Fingrid Oyj as a master's thesis for the Department of Electrical Engineering, Aalto University. During the process, I have received a lot of help and support.

I want to express my gratitude to Professor Matti Lehtonen for supervision and academic overview of my thesis. I want to express my gratitude to my superior Ari Silfverberg at Fingrid, who had a major impact for enabling this thesis work to happen. I want to thank my thesis advisor Sampsamatti Tanner for his valuable remarks and comments during the thesis project. A special thanks to colleagues at telecommunication department for their amusing presence and witty humor to brighten up my days during the writing process.

Finally, I want to thank my friends and family for the support during the whole time of my studies, especially my parents for always encouraging to pursue my goals and helping me to achieve them.

Otaniemi, 29.1.2018

Mikko M. Poranen

Contents

Symbols and abbreviations

Symbols

c	speed of light in vacuum $\approx 3 \times 10^8$ [m/s]
Cs	chemical element, cesium
D_{MS}	duration taken by a message to travel from a master clock to a slave clock
D_{SM}	duration taken by a message to travel from a slave clock to a master clock
Hz	unit of frequency
j	imaginary unit
K	base unit of temperature
v_p	propagation speed of traveling wave
Z	unit of impedance
ϕ	signal phase angle
ω	angular frequency
Δ	delta, change of quantity
Ω	electrical resistance

Abbreviations

BC	Boundary Clock
BMCA	Best Master Clock Algorithm
CT	Current Transformer
cTE	Constant Time Error
dTE	Dynamic Time Error
ESA	European Space Agency
E2E	End-to-End
FR	Fault Recorder
GM	Grand Master
GNSS	Global Navigation Satellite System
GPS	Global Positioning System
HSR	High-availability Seamless Redundancy
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IP	Internet Protocol
IRIG	Inter-Range Instrumentation Group
ITU	International Telecommunication Union
LAN	Local Area Network
LDP	Line Differential Protection
MAC	Media Access Control
MIB	Management Information Base
MPLS	Multiprotocol Label Switching
MTIE	Maximum Time Interval Error
NCIT	Non-Conventional Instrument Transformer
NERC	North America Electric Reliability Corporation

NTP	Network Time Protocol
OC	Original Clock
OCXO	Oven Controlled Crystal Oscillator
OPGW	Optical Ground Wire
PDC	Phasor Data Concentrator
PDH	Plesiochronous Digital Hierarchy
PDV	Packet Delay Variation
PDC	Phasor Data Concentrator
PDH	Plesiochronous Digital Hierarchy
PDV	Packet Delay Variation
PMU	Phasor Measurement Unit
PQ	Power Quality
PRP	Parallel Redundancy Protocol
PRTC	Primary Reference Time Clock
PPS	Pulse Per Second
PPS	Precise Positioning Service
PTP	Precision Time Protocol
PUP	Power Utility Profile
P2P	Peer-to-Peer
RMS	Root Mean Square
RSTP	Rapid Spanning Tree Protocol
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SDH	Synchronous Digital Hierarchy
SE	State Estimation
SI	International System of Units
SNMP	Simple Network Management Protocol
SNTP	Simple Network Time Protocol
SPS	Standard Positioning Service
SSU	Synchronization Supply Unit
SyncE	Synchronous Ethernet
TAI	International Atomic Time
TC	Transparent Clock
TCXO	Temperature Compensated Crystal Oscillator
TDM	Time Division Multiplexing
TE	Time Error
TIE	Time Interval Error
ToD	Time of Day
TSO	Transmission System Operator
TVE	Total Vector Error
TWFL	Traveling Wave Fault Locator
UTC	Coordinated Universal Time
VT	Voltage Transformer
WAMS	Wide Area Measurement System
WAN	Wide Area Network
WDM	Wavelength Division Multiplexing

1 Introduction

1.1 Background of the Thesis

Fingrid is Finland's national transmission system operator. It operates as a link between electricity production and regional distribution. Fingrid owns 400 kV, 220 kV and 110 kV power transmission lines and substations between them. Power grid requires telecommunication between the substations for remote control, protection and general functionalities. Communication relies mainly to fiber optic cables between the substations and data is sent and routed by telecommunication devices at the substations.

Power system has substation applications that communicates and exchanges data between substations or control center. Some of the applications require accurately time stamped data. Accurate time synchronization across the substations is essential for applications such as PMU, fault recorder, differential protection and power system fault locator. Inaccurate time synchronization between substations can cause malfunction in time dependent applications. Malfunctions may lead to financial losses. E.g. if the fault location is miscalculated due to an incorrect time stamp, it takes longer to locate and repair the fault.

Accurate synchronous time can be distributed to substations by different methods. A common way to achieve high accuracy synchronization is GPS synchronization. GPS system offers time service for public and private sector all around the world. Thus, each substation can receive time from their own local GPS receiver. Another way to distribute time is to utilize terrestrial telecommunication network. A popular terrestrial time synchronization technology is called Precision Time Protocol (PTP). There are pros and cons in every distribution method and they have to be reflected against the time synchronization requirements.

Currently Fingrid is observing possibilities to renew their telecommunication network. At the same time, it is a logical moment to review the need for reliable, accurate and synchronous time. The new next generation network could offer accurate and synchronous time as a service, which is not possible with current network. Fingrid's telecommunication department is responsible of the design and implementation for the current and possible upcoming next generation network. This thesis is made for the telecommunication department to achieve better comprehension whether the accurate and synchronous time is feasible as a service or not.

1.2 Objective of the Thesis

This thesis will answer to the questions: "Does Fingrid require accurate and synchronous time?", "How accurate it should be?" and "What is the ideal way to distribute time to the substations?". With the obtained information, Fingrid telecommunication department can design a specification for the requirements of time distribution and synchronization that can be used in the telecommunication device acquisition. The thesis will give an emphasis on the PTP time distribution protocol, since that is a likely option for the next generation telecommunication network. Other distribution protocols are reflected to PTP to find out whether it is reasonable to implement or not.

This thesis focuses on time distribution between the substations. Some speculation is included concerning time distribution inside the substations in order to provide to the reader a better picture of the overall complexity. This thesis focuses on distributing time of day rather than distributing frequency, although these two factors are related.

Section 2 of this thesis presents the time distribution methods and fundamentals around it. Section 3 describes the time dependent applications in power system. Section 4 combines the information acquired from section 3 and 4 to present the appropriate time distribution technology for Fingrid needs and speculates with various scenarios. Finally, section 5 offers a comprehensive summary and suggests topics for further study.

1.3 Fingrid's power system and telecommunication network

Fingrid Oyj is Finland's transmission system operator. It transmits electricity between electricity production sites, local distribution networks, major industrial factories and cross borders. Fingrid's transmission system contains 400 kV, 220 kV and 110 kV power lines for more than 14 000 meters and over 100 electrical substations. Figure 1 presents Fingrid's power transmission network. [1]

Fingrid telecommunication network operates alongside the power transmission network. Telecommunication devices are typically located at the substations. Devices at the substation are connected through substation automation to the intelligent electronic devices (IED) that supports substation applications. Fiber optic cables connect the communication devices on different substations.

Fiber optic cable is recommended for communications because it can transfer long and short distances large capacity of data. In addition, fiber is immune to electromagnetic interference. There are underground fiber optic cables and optical ground wires (OPGW). OPGW is primarily placed in the topmost position of the transmission line. Upper layer protects electrical conductors from lighting strikes and inner layer contains fiber optic cable where data is being transferred.

The telecommunication network operates on different data transfer techniques such as Plesiochronous Digital Hierarchy (PDH), Synchronous Digital Hierarchy (SDH), Multiprotocol Label Switching (MPLS) and direct fiber connection. The technique used in the network depends on which function the transferred data is for.

Telecommunication network improves the function of teleprotection, enables remote operation from central control center and Internet Protocol (IP) based traffic over a broadband connection. IP based traffic to substations includes e.g. remote connections, Voice over IP telephony (VoIP), internet connectivity, camera surveillance and access control.

Teleprotection operates on direct fiber connections and over telecommunications. RTU utilizes PDH and IP. Normally RTU and teleprotection connections are duplicated for better availability and operation that is more reliable. Broadband utilizes both SDH and direct fiber connections.

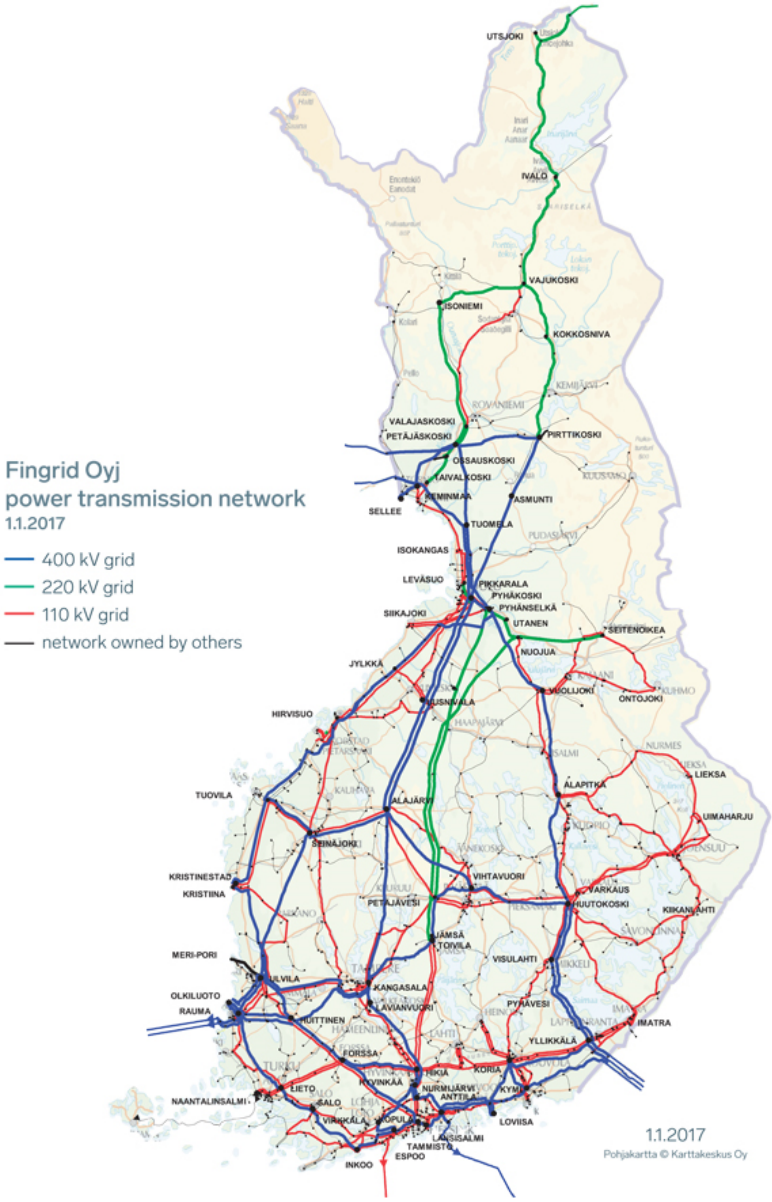


Figure 1: Fingrid power transmission network [1]

Now Fingrid telecommunication department is seeking an alternative technology to replace the current SDH and PDH technology. PDH and SDH technology is getting older, it is not taught in schools any more, thus it is difficult to find new experts to maintain the current network. Additionally the demand for SDH and PDH is decreasing which again decreases the supply of the equipment. The new selected technology will be native MPLS, which allows scalable and protocol independent wide area network (WAN) communication. [2]

2 Time distribution

This section contains information of how it is possible to have synchronous time on the substations. First, the terms related to this thesis are opened in order to avoid misunderstandings while reading. Next, there is a subsection about time and time error, which clarifies the fundamentals what it means to distribute time. Then different time distribution techniques are introduced and compared. Synchronous Ethernet protocol is explained because of its relation to PTP time distribution protocol. Finally, PTP protocols and redundancy sections explains technical aspects that impacts to future time distribution implementation.

2.1 Terms

This subsection clarifies the terms used in this thesis concerning time distribution and telecommunications.

Clock device: A node in a network that can issue or receive any time distribution protocol.

Epoch: "The origin of a timescale." [3]

Frequency synchronization: Clocks that have same frequency repeats an event in same period of time. The event may occur in different time instant as long as the period of time between repetitions remains the same.

IEC 61850: Defines communication protocols at electrical substations. Recommends 10 μs or less time synchronization accuracy. [4]

Layer: The Open Systems Interconnected model (OSI model) characterizes the communication functions to 7 different layers.

Node: A clock device that can issue or receive any time distribution protocol on a network.

Phase synchronization: "This term implies that all associated nodes have access to reference timing signals whose significant events occur at the same instant (within the relevant phase accuracy requirement). In other words, the term refers to the process of aligning clock with respect to phase." [5] Figure 2 illustrates phase synchronization. Phase synchronized clocks are frequency synchronized but may different time of day.

Synchronized clocks: "Two clocks are synchronized to a specified uncertainty if they have the same epoch and their measurements of the time of a single event at an arbitrary time differ by no more than that uncertainty." [3] The clocks could be in a telecommunication network e.g. switches or routers. There are different methods to synchronize clocks. Section 2.3 presents different protocols to synchronize clocks by distributing time.

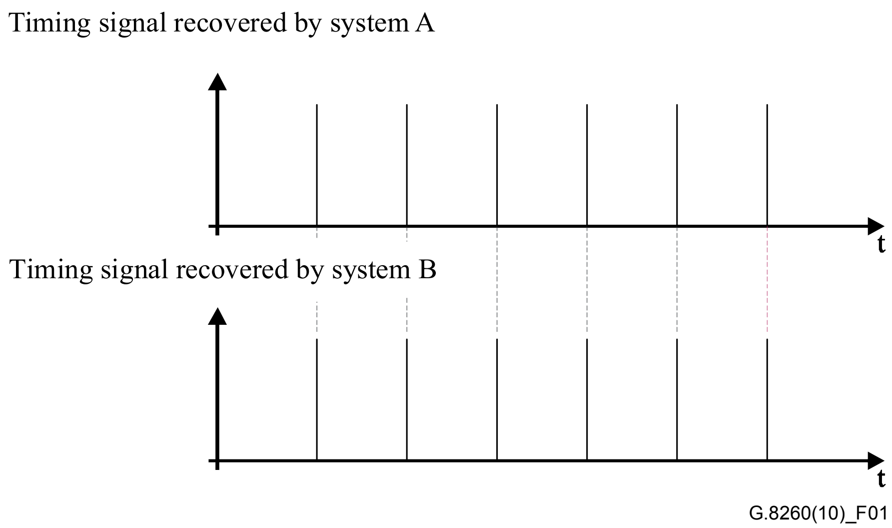


Figure 2: Phase synchronization [5]

Syntonized clocks: "Two clocks are syntonized if the duration of the second is the same on both, which means the time as measured by each advances at the same rate." [3] Syntonized clocks can have different time of day.

TAI: International Atomic Time is the primary time scale maintained by international standard laboratories. [5]

Time accuracy: PTP power profile defines time accuracy when time error is not exceeded by 99,7% of the measurements, evaluated over a series of 1000 measurements in steady state. [6]

Time error: PTP power profile defines time error as a deviation from the time reference used for measurement or synchronization caused by a network element, evaluated over a short time span (a few sync intervals). [6]

Time distribution: If a clock is synchronized it receives time from an outer source by time distribution. Time distribution is part of the synchronization process.

Time of Day: Time synchronization distributes Time of Day. Synchronization contains information about seconds from a certain epoch.

Time reference: A timing signal which is traceable to an internationally regocnized time standard or a time scale. [5]

Time synchronization: "The distribution of a time reference to the real-time clocks of a telecommunication network. All the associated nodes have access to information about time (in other words, each period of the reference timing signal is marked and dated) and share a common time scale and related epoch (within the relevant time accuracy requirement)." See also **Synchronized**

clocks. Distributing time synchronization is a way to achieve phase synchronization. [5] Figure 3 illustrates time synchronization. Time synchronized clocks have the same time of day.

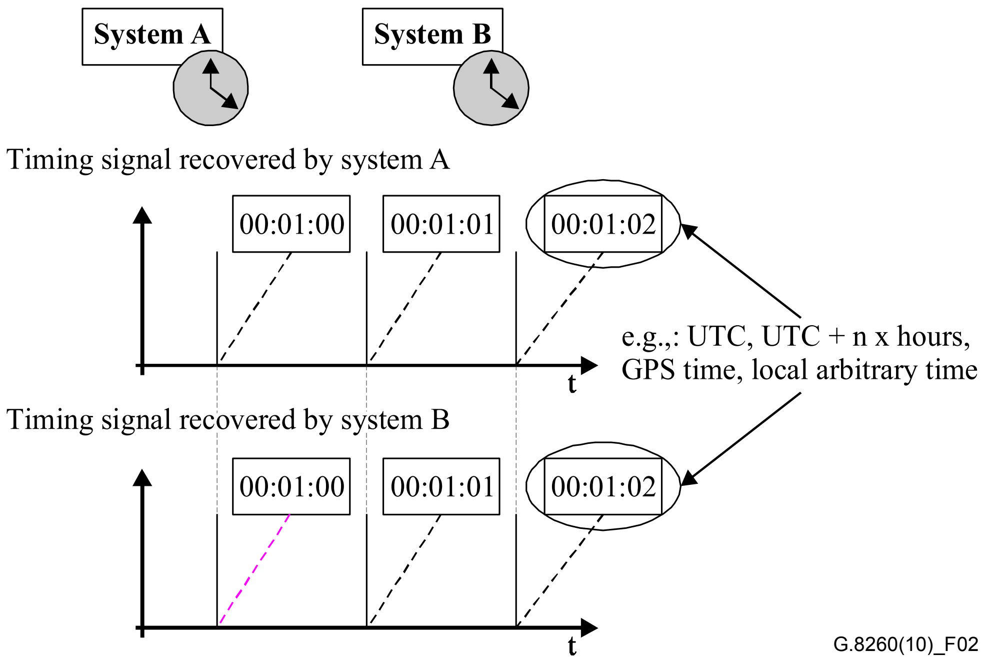


Figure 3: Time synchronization [5]

Time source: A source of time from where time is distributed to a device.

UTC: Coordinated Universal Time is a time scale maintained by the international standards laboratories. UTC is based on TAI, but extends it with leap seconds. [5]

2.2 Time and Time Error

This thesis is about time distribution and applications that relies on accurate and synchronous time. The purpose of this section is to discuss about time that is a fundamental part of understanding the nature of time distribution. Time Error is an important measure to evaluate the performance of time distribution.

Time allows us ordering the events from past to present to future. Measuring time requires a concept of a fixed period of time, which is typically provided by a regularly repeating event with constant period called frequency. Historically, a solar day was a principal measure of time. [7]

Time is a fundamental physical dimension, however the measurement of it is relative. Initially one has to define the epoch, which means the start time of the measurement and the rate of advancement. Time is usually informed by seconds from an epoch. For example different calendars uses different epoch, the Georgian calendar counted years from the presumed birth of Christ and the Roman calendar dates from the founding of Rome. The rate of advancement is determined in the current physical system as seconds. The SI unit of the second is defined as: "The second is the duration of 9,192,631,770 periods of the radiation corresponding to the transition between the two hyperfine levels of the ground state of the cesium 133 atom in its ground state at a temperature of 0 K". [7]

Coordinated Universal Time (UTC) is the current civil and legal time standard. UTC is based on the Georgian calendar epoch and has the same rate of advancement as International Atomic Time (TAI). UTC differs from TAI by number of seconds for compensation of earth slowing down relative to the oscillations of a Cs atom. Cs atom defines the frequency in a Cs atomic clock. [7]

UTC time reference allows the measurement of time at different physical places by clock devices. The idea of time distribution is to adjust the rate and seconds from the epoch to match the distributed time reference. A clock may be adjusted to advance at the correct rate and set to match seconds from reference time epoch. Later observation of the clock time may be different compared to the reference time due to inaccuracy in either the rate adjustment and/or the original setting. This relative error to time reference is called time error. [7]

One way to distribute reference time to different locations is to physically transport a clock between the locations, and adjust the local clock to match the transported clock. In this case, the transported clock would be a master clock and the local clocks who receives the time would be slaves. Thus, the clock forms a hierarchical structure. Another way is sending a message to a slave clock that contains the time from a master clock. This information is useful only if the receiving end knows for how long it took to deliver the message. The recipient can adjust its clock to match the time received plus the delivery duration. [7]

There are two common methods to estimate the delivery time. First, one is by measuring the round trip time between two clocks by sending multiple messages containing time stamps from both devices and assuming that the delivery time is half of the round trip time. Protocols called PTP and NTP uses this method. Another method takes advantage of the knowledge of the distance between and locations of sender and receiver. Global Navigation Satellite System (GNSS) takes advantages of that information when it calculates the delay in its time message. [7] Time distribution methods are further discussed in section 2.3.

2.2.1 Time error

Every time distribution method has its own error sources that results to time error, regardless of the purpose to distribute the exact reference time. "Time error is a measure of the difference between the time, relative to the epoch, reported by a local clock and a reference clock." [7] The time error is not constant and may be expressed as a function of time. For example, if the rate of the local clock's oscillator deviates from the reference, the time error will gradually increase.

Time error is often divided to constant and dynamic. Figure 4 illustrates time error in the function of time and visualizes constant and dynamic time error. Constant time error (cTE) is the mean level of the time error function. Dynamic time error (dTE) is the amplitude of the function. Maximum time error (Max|TE|) is the maximum amplitude of the time error function.

Another term that often occurs is Time Interval Error (TIE), which illustrates the change of time error. Time error is the difference relative to the epoch, whereas TIE is the change time error relative to the start of measurement and presents. Maximum time interval error (MTIE) is the maximum change in TIE and equals to the peak-to-peak value of the dTE. Figure 5 illustrates time interval error.

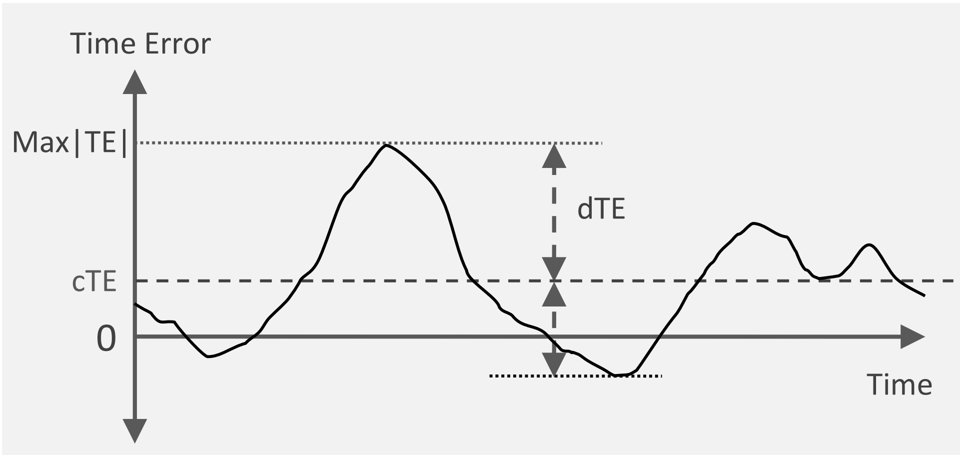


Figure 4: Constant and dynamic time error presented in time error function [7]

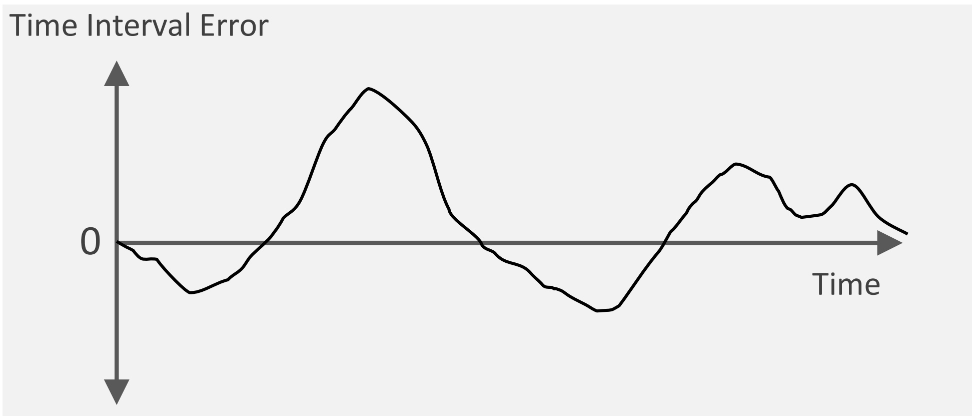


Figure 5: Time Interval Error [7]

2.2.2 Time error sources

There are a few different sources for time error. Error in set of time e.g. to a wrong epoch can cause a permanent offset. A wrong rate of phase can cause gradually increasing time error. A clock with wrong phase which is corrected regularly has time error with a saw tooth shape as presented in Figure 10. Temperature and aging effects on the performance of an oscillator inside a clock and causes wander in time error. There are also specific time error sources in network time distribution methods such as NTP and PTP. [7]

In packet networks, Constant time error (cTE) arises if there are difference in forward and reverse network delay. Packet protocols assumes that one-way delay is half of the round trip time. Thus if the difference in forward and reverse network delay causes an error in time offset calculation. One-way delay can be measured only with an independent time source connected to both ends, such as GPS. This kind of error is called asymmetry and there are three main causes for it: Node asymmetry, Link asymmetry and Route asymmetry. [7]

Node asymmetry is caused when the reverse and forward traffic inside a switch has different delay. **Link asymmetry** is caused by asymmetry of optical fibers or cables between the nodes. They could be different length or operate with different wavelengths. **Route asymmetry** occurs when data packets do not take the same route in each direction. [7]

Dynamic time error (dTE) occurs in packet networks when the data packets take different length of time to travel through the network. This is called Packet delay variation (PDV). Packets usually has to queue in the node before they are transmitted to their next destination. This queueing time may vary and cause PDV. There are possibility to prioritize packets that contain critical information such as time synchronization packets and reduce their queueing time. However, even then the PDV cannot be eliminated totally. [7]

Fluctuation in the frequency of a clock oscillator is another source of dTE. Aging and variations in the temperature may change the clock frequency to run too fast or slow. In addition, timestamp quantisation may cause jitter both in time and position of the timestamp. [7]

These issues causes errors along the time distribution network. The time distribution protocols try to maintain the time error in sufficient limits. Each node along the time distribution path causes a certain amount of time error. Therefore, time error increases cumulatively along the distribution chain. Often this issue is processed by calculating a time error budget for a certain distribution path. [7]

2.2.3 Time error budget

ITU G.8271.1 "Network limits for time synchronization in packet networks" standard defines a reference model for Precision Time Protocol (PTP) deployment. The model divides the time error budget into four interfaces:

A: Time accuracy and stability output of a primary reference time clock (PRTC)

B: Packet timing interface at output of PTP Telecom Grand master (T-GM)

C: Budget at the edge of a network

D: End applications e.g. at a substation. [7]

This standard requires 1.5 μs accuracy which is applied in mobile base stations. It presents an applicable idea of designing a time error budget for telecommunication network that serves substations in the power system. Figure 6 illustrates the time error budget and its different sections.

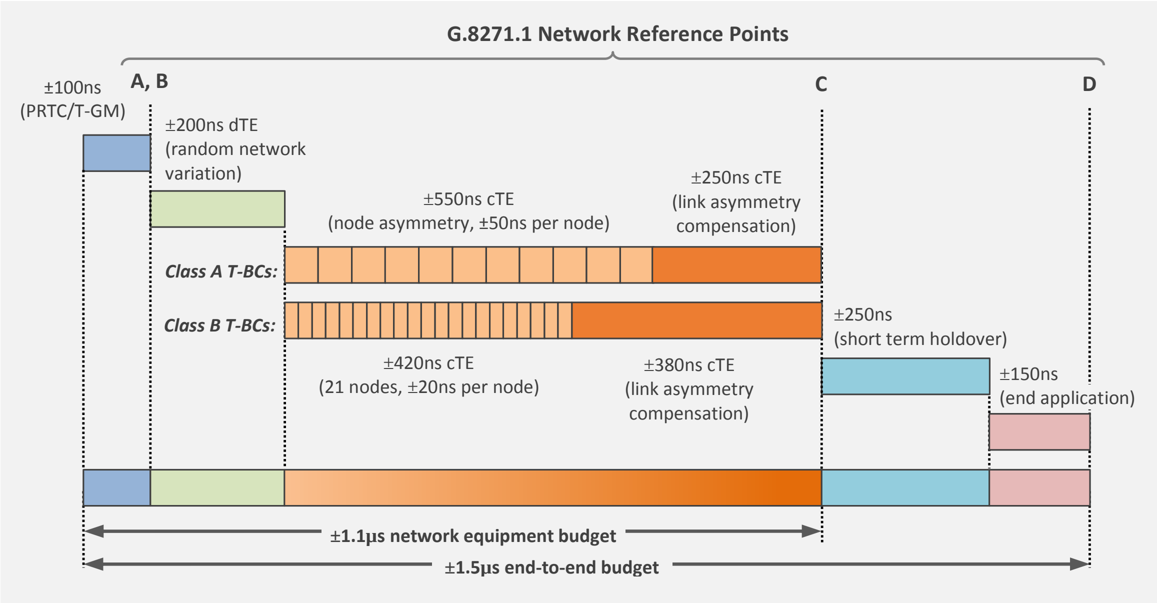


Figure 6: Time error budget with network reference points presented in ITU G.8271.1 standard [7]

Time error of network equipment is divided into cTE and dTE. TE budget for cTE is allocated to be larger than dTE. This is because cTE increases cumulatively in each node, while dTE is filtered out by the clocks and increases rather logarithmically. There are also two different kind of Telecom Boundary clocks (T-BC) that illustrates different error outcomes with different hardware setups. Node and Link asymmetries have been taken into account. Each time error presented in Figure 6 is a measure from the reference time e.g. UTC. [7]

2.3 Time distribution methods

This chapter gathers different time distribution methods. Time distribution should be able to provide time synchronization between the substations and not only inside a substation. Following methods could be used for time distribution in power system but each of them has pros and cons. PTP and GNSS distribution methods have a strong emphasis because both of them are relevant for Fingrid. PTP is already selected to be tested in near future. GNSS is already used as a time source for some applications at Fingrid substations. The purpose of this chapter is to further investigate relevant time distribution methods. After the knowledge is gained, it is possible to reflect whether PTP is the ideal protocol to continue with.

2.3.1 Inter-Range Instrumentation Group

Inter-Range Instrumentation Group (IRIG) standard defines a common set of time codes, known as the IRIG codes. The latest version is the IRIG standard 200-04, "IRIG Serial Time Code Formats" from 2004. IRIG code B (IRIG-B) has become widely accepted for time distribution in substations. IRIG-B continuously transmits binary data about time of day and accurate on-time mark. IRIG-B pulse rate is 100 pulse per second, which produces 100 bits of data. 74 of the bits contains time, date, time changes, and time quality information of the time signal. IEEE-1344 extension for IRIG-B brought additional features, including Calendar Year, Leap seconds, Daylight Saving Time, Local time offset, Time Quality, Parity, and Position identifiers. [8]

IRIG-B code delivers time either as unmodulated format or as modulated signal with a 1 kHz carrier. Unmodulated IRIG-B signal can be transmitted by RS-485 differential signal over shielded twisted-pair cable and RS-232 over shielded cable for short distances. Modulated IRIG-B signal can be transmitted by coaxial cable terminated in 50 Ω or shielded twisted-pair cable. [8]

IRIG-B code has become commonly accepted for time distribution inside substations. IEDs on the substation synchronizes their clocks based on this signal. IEDs must support the IRIG-B coding and its extension. IRIG-B reaches accuracy of microseconds. It should be enough for most of the substation applications. IRIG-B does not take into account cable delay. It can be an issue in long distances, since a meter causes 3 to 5 ns delay. Because of lack of delay correction and requirement for dedicated cabling IRIG-B is not suitable for Fingrid to distribute time over long distances between the substations. [8]

2.3.2 Pulse Per Second

Pulse Per Second (PPS) is an electrical signal that repeats once per second. PPS does not carry time of day, therefore it has been supplanted by IRIG time codes that distribute time of day with equal accuracy. It is commonly used for phase synchronization and in standard laboratories to compare time and frequency sources at high accuracy. PPS reaches to sub microsecond accuracy. [8] PPS is not an alternative for Fingrid because the distribution method should include Time of Day information.

2.3.3 Network Time Protocol

Network Time Protocol (NTP), defined in the RFC 5905, provides time transfer over data networks. The purpose of the NTP protocol is to convey time from primary servers to secondary servers and clients via telecommunication network. [9] NTP transmits time information by timestamped messages. NTP algorithm adjusts the clock of an IED monotonically without rapid jumps. Thus, it does not just simply copy the timestamp received. NTP takes into account the delay caused by cables, switches, signal adapters and other devices. [10]

Normally some of the IEDs do not support NTP but instead they support Simple Network Time Protocol (SNTP) implementation. The messages of NTP and SNTP are equal, but SNTP does not keep the internal clock stabile over long periods and does not support every NTP algorithm. The first edition of IEC61850 recommended the SNTP for the time synchronization at the substation level. However neither SNTP nor NTP does not reach to time accuracy, which would be enough for all substation applications. In real world SNTP implementations achieve accuracy between 2 ms to 10 ms. [10] Updated version of IEC61850 recommends PTP for time synchronization at the substation level. [11]

NTP is not a feasible solution for Fingrid to distribute time between the substations. NTP is not accurate enough. NTP could be used together with 1-PPS signal, which would increase the total accuracy. However this implementation is not feasible compared to PTP, because the setup would require two time information connections for the devices [11]. Now NTP is used at some Fingrid substations to distribute time inside the substation for some of the applications that do not require high time accuracy. Additionally NTP is used for Fingrid Office-network synchronization.

2.3.4 Precision Time Protocol

Precision Time Protocol (PTP) is a time distribution method that uses existing telecommunication network for time distribution. PTP protocol was developed to provide time synchronization over packet network with the same precision as the IRIG-B signals using similar software concept to NTP[8]. International Standard IEEE 1588 defines PTP protocol for networked measurement and control systems. This thesis is based on the year 2008 PTP standard, which is also referred to PTP version 2 or PTPv2.

IEEE 1588 does not set any performance requirements, but provides methods for PTP time distribution. Another standard IEEE Standard Profile for Use of IEEE 1588 Precision Time Protocol in Power System Applications, also known as The Power Profile, offers an extended profile for the use of PTP in power system protection, control, automation, and data communication applications utilizing an Ethernet communications architecture. [3][6]

PTP organizes real-time clocks into a master slave hierarchy, where master and slave exchanges PTP-messages. A clock device time stamps messages from transmitting and receipt side. Slave clock adjusts its clock with the timing information acquired from the message exchange to the time of its master. PTP messages consists of event and general messages. Event messages require accurate timestamps at both transmission and receipt. General messages do not require accurate timestamps. Timestamp precision affects the time accuracy of a PTP system. Timestamping can be either software-only or hardware-aided. Former reaches time deviation of tens of microseconds and latter reaches deviation of tens of nanoseconds.[12]

The set of event messages consists of following messages:

- Sync: For the slave clock synchronization the master sends a sync message to the slave and notes the time t_1 at which it was sent. The slave receives the Sync message and notes the time of reception t_2.
- Delay_Req: For the slave clock synchronization the slave sends a Delay_Req message to the master and notes the time t_3 at which it was sent. The master receives the Delay_Req messages and notes the time of reception t_4.
- Pdelay_Req: For the link delay measurement port-1 issues a Pdelay_Req message. Port-1 device notes the time t_1 at which it was sent. Port-2 device receives the Pdelay_Req message and notes the time of reception t_2.
- Pdelay_Resp: For the link delay measurement port-2 issues a Pdelay_Resp message. Port-2 device notes the time t_3 at which it was sent. Port-1 device receives the Pdelay_Resp message and notes the time t_4 at which it was sent. [3]

The set of general messages consists of:

- Announce: The Announce message is used for the Best Master Clock algorithm to establish the synchronization hierarchy.
- Follow_Up: Master sends a Follow_Up message after the Sync message. The Follow_Up message contains information of Sync message transmission time for the Slave. (Follow_Up message is used only in two step clocks.)
- Delay_Resp: Master answers to a Delay_Req message with a Delay_Resp message. Delay_Resp message contains timing information of the Delay_Req arrival.
- Pdelay_Resp_Follow_Up: This message is used to measure the link delay between two clock ports implementing the peer delay mechanism. Pdelay_Resp_Follow_Up contains timing information of the Pdelay_Resp departure time.
- Management: Management messages are used to query and update the PTP data sets maintained by clocks. These messages are also used to customize a PTP system and for initialization and fault management.
- Signaling: The signaling messages are used for communication between clocks for all other purposes. For example, signaling messages can be used for negotiation of rate of unicast messages between a master and its slaves. [3][12]

PTP clock synchronization contains five different basic clock types:

- Ordinary clock (OC) has a single PTP port. It can serve as a slave in a master-slave hierarchy or as a grandmaster. Port in ordinary clock can be implemented to use synchronization and peer delay mechanisms.

- Boundary clock (BC) has several PTP ports. It can serve as a slave, a master or a grandmaster. Each port independently works like the port of an ordinary clock.
- Transparent clock (TC) corrects and forwards PTP messages. Transparent clock has multiple PTP-ports. It can not be neither a master nor a slave clock but it is a bridge between the two. TC is able to estimate the residence time of a packet in the device.
- Management node has one or more connections to the network. It serves as a configuration and monitoring device for the PTP network.

There are two different kind of TCs: End-to-End TC (E2E TC) and Peer-to-Peer TC (P2P TC). The E2E TC and P2P TC differs in the way they correct and handle the PTP timing messages. E2E TC corrects and forwards all timing messages while P2P TC only corrects and forwards Sync and Follow_Up. E2E TC uses E2E delay mechanism while P2P TC uses Peer delay mechanism. E2E TCs forwards and corrects timing messages as in Figure 8. Peer delay mechanism message exchange includes the Sync and Follow_Up messages from Figure 8, but replaces the network delay calculation by its own Peer delay calculation. Peer delay mechanism divides the network delay calculation into two parts: from master device to TC and from TC to slave device. [3]

The P2P delay measurement is more sophisticated and precise, but relies that the neighboring devices are 1588 capable. The E2E mechanism allows non-PTP devices, which again degrades the overall time synchronization accuracy.

Establishing the master-slave hierarchy with Best Master Clock Algorithm

PTP network builds its master-slave hierarchy with the Best Master Clock Algorithm (BMCA). Each PTP-device sends announce messages from its ports to neighbouring devices. Announce message contains data about the clock accuracy from the sender. The announce message is used to determine whether a newly discovered clock - a foreign master - is better than the local clock itself. A foreign master means that the best clock may be "behind" the initial neighbor device.

Foreign master data is contained in the grandmaster fields of the announce message. BMC data comparison algorithm compares the data set received from the announce message to the device's own clock accuracy data set. The comparison algorithm uses priority list which can be configured by the user. When the algorithm knows which clock is better, the state decision algorithm determines which state the device will obtain. More information can be found from [3].

PTP-port can obtain one of the three following states:

1. Master: The port is the source of the time on the path served by the port.
2. Slave: The port synchronizes to the device on the path with the port that is in the master state.

3. Passive: The port is not the master on the path nor does it synchronize to a master. Passive state is set to avoid loop situation. BMC algorithm constructs a tree formation by setting parts of the loop to a passive state. [3]

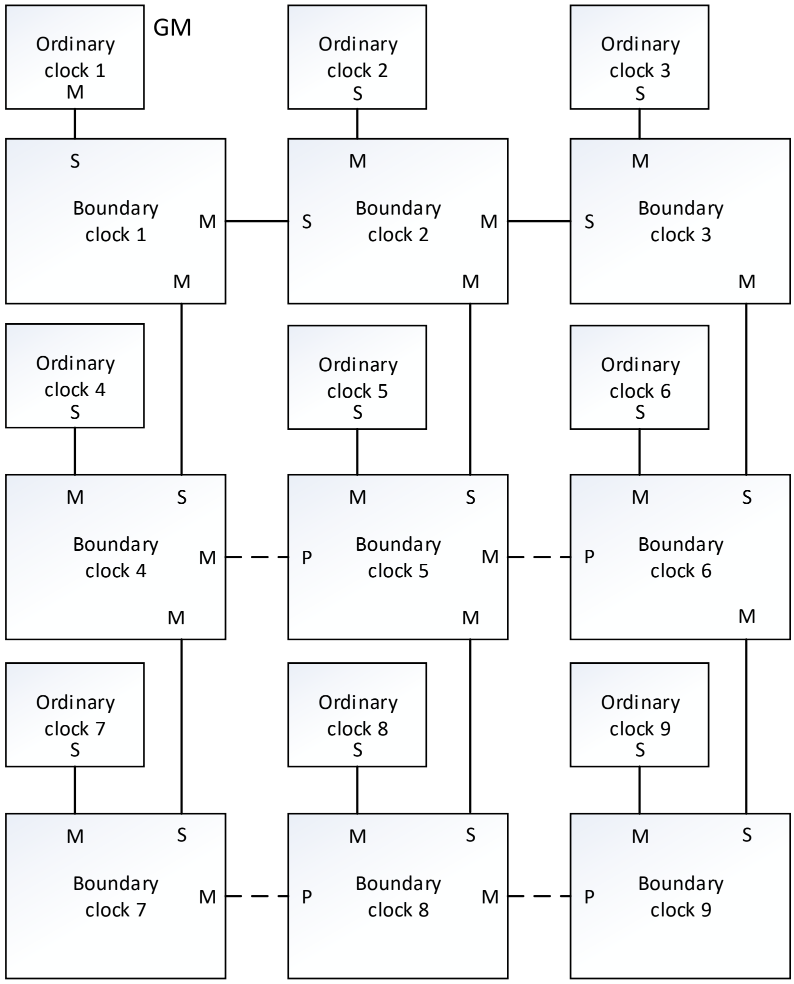


Figure 7: Example of pruned mesh PTP-network topology. Modified from [3].

Figure 7 illustrates an example of PTP-network topology. This meshed network is reduced to a tree-structured master-slave hierarchy by the PTP protocol. The BMCA algorithm selects the states of some ports to passive in boundary clocks to avoid cyclic paths. Passive paths are dashed lines in the Figure 7. Ordinary clock-1 is the grandmaster. Its port is master to boundary clock-1 and the port on boundary clock-1 side is slave. M in Figure 7 indicates master state, S indicates slave state and P indicates passive state.

Every path between boundary and ordinary clocks can contain transparent clocks. Transparent clocks are not presented in picture 7 because they do not participate in the master-slave hierarchy. [3]

PTP synchronization message exchange

In PTP synchronization message exchange ordinary or boundary clocks communicates on the path linking the two clocks. These timing messages enable master time distribution to the slave. Figure 8 illustrates timing message exchange between a master and its slave. The timing message exchange goes as follows:

1. The master sends a Sync message to the slave and notes the time t_1 at which it was sent.

2. The slave receives the Sync message and notes the time of reception t_2.

3. The master conveys the timestamp t_1 to the slave either in Sync message or in Follow_Up message, depending on hardware used.

4. The slave sends a Delay_Req message to the master and notes the time t_3 at which it was sent.

5. The master receives the Delay_Req message and notes the time of reception t_4

6. The master conveys to the slave the timestamp t_4 by embedding it in a Delay_Resp message.

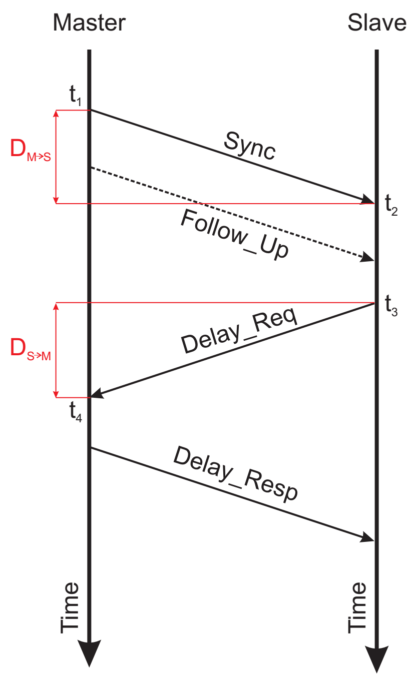


Figure 8: Synchronization message exchange [12]

After the timing message exchange, the slave knows all four timestamps. Slave uses these four timestamps to compute the offset and adjusts its clock with respect to the master. This calculation assumes that master to slave and slave to master propagation time is equal. Any asymmetry in propagation time causes error in computation. Slave offset O can be calculated from following formula:

$$O = \frac{(t_2 - t_1) - (t_4 - t_3)}{2}. \tag{1}$$

PTP advantage and disadvantages

PTP is a feasible solution if there is a robust network to exploit, since PTP requires communication between the network devices for the PTP-message exchange. Fingrid has an existing fiber optic cable network connecting substations together, which is a feasible platform for PTP. PTP reaches to sub microsecond accuracy with hardware timestamping. This accuracy should be enough for most of the applications in Fingrid power system. More about time requirements of substation applications are in section 3.

PTP has also some uncertainty sources. Each component taking part in PTP time distribution introduces error and uncertainty. A fundamental part of PTP is its time source. Time source uncertainty depends on the quality of its clock. A clock consists in a simplified manner from an oscillator and a counter. An ideal oscillator has constant frequency but in reality it is a complex function of the time. Oscillator uncertainty depends on e.g. pressure, temperature and the age of the oscillator.

In addition, traffic condition inside the PTP network, the number of PTP and non-PTP devices between the path from master to slave, the presence of asymmetrical delay and the network load. All these components decrease the performance of PTP protocol. More detailed description of PTP uncertainties can be found from [12].

However, when all these factors are known it is possible to estimate an inaccuracy marginal of the PTP aided network. Each node in the network causes a cumulative inaccuracy marginal. After estimating the inaccuracy marginal, it is possible to evaluate whether the marginal is sufficient for the applications behind the telecommunication network. This process is also called as time error budgeting.

PTP should be applicable for both inside and between substation time synchronization and thus a sufficient option for Fingrid. A pilot implementation for terrestrial synchronization is introduced in [41]. The Uruguayan electrical company deployed 11 substations in PTP time distribution chain, and covered distance of 400 km. PTP was used with power profile, and they managed to distribute time within sub microsecond level.

2.3.5 Global Navigation Satellite Systems

Global Navigation Satellite Systems (GNSS) provides location and timing information for the receivers around the globe. GNSS provides UTC traceable time and phase for every node without cumulative error [30]. Each substation in the power system can receive timing signal from the satellites with an individual GNSS receiver. This time signal is then distributed to different applications inside the substation. There is no need for synchronization between the substations when every substation GNSS receiver acquires the time from the same time source. This way telecommunication network is not needed for time distribution. Figure 9 illustrates the basic concept of GNSS time distribution.

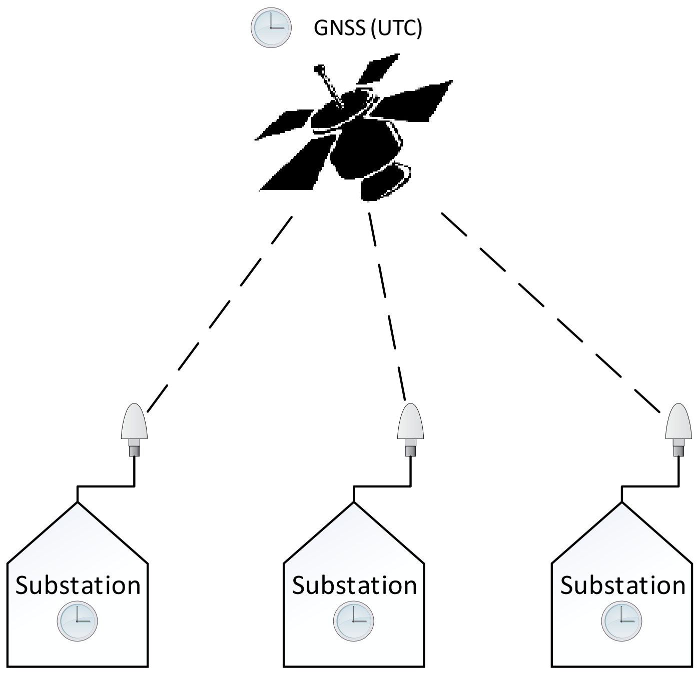


Figure 9: Principle of GNSS time distribution

GNSS satellites provides UTC time scale to GNSS receivers located at the substations. The receiver needs to see four satellites to determine precise position and time. Although after the position is known, one satellite is enough to maintain accurate time. If there are more than one satellite visible, the time from the satellites can be averaged and thus result in reduced error in the time estimate. [8]

There are four different GNSS: GPS, Galileo, GLONASS and BeiDou. GPS is the most mature system among GNSS. Galileo, Glonass and BeiDou are under critical development and they are planned to reach full operation around year 2020. After the development, each system should have similar performance parameters as GPS. Next, we will go through characteristics of each system.

GPS

GPS provides reliable positioning, navigation and timing services to civilian and military users around the globe. The U.S. Air Force developed GPS in 1978 and it is still an U.S. owned utility. GPS is a mature system which is being developed all the time. At the moment there is a modernization program going on, which will improve GPS performance, including more robust resistance to interference. Current modernization program began in 2005 and the last phase of it began in 2015. [13]

GPS satellites are equipped with atomic clocks that are precise within nanoseconds [8].

GPS offers two different service levels: The Standard Positioning Service (SPS) and The Precise Positioning Service (PPS). The SPS provides timing and positioning service broadcasted at GPS L1 frequency and is available to all GPS users. The PPS provides highly accurate military positioning, velocity and timing services broadcasted at GPS L1 and L2 frequencies. PPS is only for authorized users, since both frequencies are encrypted. SPS and PPS have both same time transfer accuracy which is <40 ns 95% of the time. Both PPS and SPS have the same constellation availability of >98% probability for 21 healthy satellites. [13]

As we notice, PPS and SPS have similar performance capabilities. PPS advantages are faster ephemeris updates and corrections, spoofing prevention by encryption and better delay correction due to dual signal. GPS is interoperable with other GNSS systems. Interoperating can improve some of the performance parameters. [13]

Galileo

Galileo provides reliable positioning, navigation and timing services worldwide free for all. Galileo is European program funded by European Union and European Space Agency (ESA). Compared to GPS, Galileo is still relatively immature system. Galileo program started in 2005 and consists of three different phases. The last phase estimated completion year is 2020. At this full operational capability phase, Galileo has 30 satellites. Galileo is being designed to be interoperable with other GNSS. [14]

Galileo offers two services: Open Service (OS) and Public Regulated Service (PRS). OS has availability of 99,8% and its Timing accuracy is 30 ns. PRS has availability of 99,5% and its timing accuracy is 100 ns. There will be also a third service called Commercial Service, which will be operated by commercial service providers. [14]

Glonass

GLONASS provides reliable positioning, navigation and timing services worldwide free for all. GLONASS receivers uses an alternative and complementary method, which is based on triangulation principles for positioning, compared to GPS, Beidou and Galileo. GLONASS is operated by the Russian Federation and its roots is from Soviet Union navigation system in 1967. In January 2012 there were 31 GLONASS satellites in orbit and 23 of them were operating. Current modernization program is scheduled to be finished in 2020. The aim of the program is to ensure that GLONASS performances are similar to those of GPS. [15]

GLONASS offers two different services as GPS: SPS and PPS. SPS is an open free of charge service. SPS offers two civil signals G1 and G2. PPS is only for military and authorized users. PPS also operates on two frequency bands G1 and G2. There is no updated information about GLONASS performance. Before starting its modernization plan in the year 2000, GLONASS had timing accuracy within 200 ns. In 2011, it has been demonstrated that GLONASS is slightly less accurate than GPS. [15]

BeiDou

BeiDou is China's satellite navigation system that provides positioning, navigation and timing services to users around the world. BeiDou is still being developed and is expected to provide global navigation services by 2020. BeiDou aims to provide services similarly to GPS, GLONASS and Galileo systems. In 2016, there were 22 satellites that were able to provide initial Operational Service. [16]

The Global BeiDou system will offer four services: Open service, Authorized service, Wide area differential positioning service and Short message service. BeiDou timing accuracy performance is planned to be 50 ns when the system is ready. [16]

GNSS suitability for time distribution

GNSS is a worthy candidate for time distribution to Fingrid substations. GPS is already used in PMU applications in Northern Europe and in power system fault location applications in Fingrid. Usually even if GNSS is not the main time distribution method, it is used as a time reference and then that reference time is distributed by another protocol. GNSS's accuracy is within tens of nanoseconds, which is enough for every application. The signal is free to use if one has a GNSS receiver.

GNSS vulnerability

GNSS disadvantage is its vulnerability. The critical applications of the user may be dependent to one service provider such as GPS. GNSS signal is vulnerable to jamming, spoofing, and may face accidental receiver malfunctions. Vulnerabilities should be taken to account when critical infrastructure, in this case power system, relies on GNSS signal. For this reason, the user should be at least capable to change between different GNSS sources in case one of them fails.

A jammer denies nearby GNSS receivers to access GPS signal by emitting high-power interference signal. Spoofing is counterfeiting GNSS signal to overpower the authentic signal. Spoofer manipulates a victim receiver's position, time, or both. An attacker could cause harm to power system by disturbing the GNSS receivers attached to critical power system applications. [17]

Fortunately, there are methods to enhance civil GNSS receivers' robustness against spoofing, jamming and accidental receiver malfunctions. Spoofing could be detected by using unpredictable information carried by the GPS signal to ensure its authenticity, or by observing changes in power of the input signal. More about different countermeasures for spoofing, jamming and receiver malfunctions can be found from [17].

2.3.6 White Rabbit

White Rabbit is an extension to IEEE 1588 PTP protocol. White Rabbit protocol is still in progress and is not yet published. It will be called a "High Accuracy" profile or "PTPv3". The IEEE 1588 standardization working group is going to introduce it in mid-2018. The protocol enhances support for synchronization better than 1 nanosecond. It is a combination of 1 Gbit Synchronous Ethernet and a PTP-like hardware time-stamping protocol. Initially White Rabbit was designed for lengths less than 10 km, however it has been proved to work at up to 1000 km distances. [18]

White Rabbit protocol takes into account the link asymmetry, while PTPv2 assumes master to slave and slave to master time to be equal. White Rabbit uses a digital dual-mixer time-difference technique that enhances the precision of time-stamps to the picosecond level. [18]

Statnett, the transmission system operator in Norway, is going to test White Rabbit protocol for their telecommunication network. First results from their test network are assumed ready in 2018. White Rabbit could be a feasible solution also for Fingrid. It seems to be the most accurate time distribution method so far. Important questions are that if Fingrid needs such an accurate time and if PTPv2 already offers sufficient time accuracy.

2.3.7 Comparison of the time distribution methods

Table 1 includes each protocol that were discussed. Typical accuracy -field illustrates a certain level of accuracy that usually is achieved with the protocol. Real life implementations can differ from the values in the Table 1. Time of Day -field informs if the protocol supports distribution of time of day. Dedicated cabling means if a device supporting that certain time distribution method needs an extra input just for the time distribution. WAN Suitable field indicates if the method is feasible for time distribution across WAN. White Rabbit is not on the Table 1 because while this thesis process the standard has not been published.

Table 1: Time distribution methods and their characteristics

Protocol	Typical Accuracy	Time of Day	Dedicated cabling	WAN Suitable
PPS	1 μs	No	Yes	No
IRIG-B	1 μs	Yes	Yes	No
NTP	1 ms	Yes	No	Yes
GNSS	<1 μs	Yes	No	Yes
PTP	<1 μs	Yes	No	Yes

PPS is accurate enough for the substation applications, however it does not distribute time of day and requires dedicated cabling. NTP is not accurate enough, though its advantage is that it does not require any dedicated cabling but uses the existing packet network. IRIG-B is more accurate than NTP, but its disadvantage is the need for dedicated cabling.

PTP protocol was designed to provide time synchronization over Ethernet network with better precision than NTP. PTP accuracy could be enough for all the substation applications, although it will be seen only after the real life implementation. PTP accuracy should be tested first in a small-scale laboratory set up, which should provide more information about the performance of PTP.

GNSS (GPS) is one of the most accurate time distribution methods. It is used at Fingrid substations for the applications that requires high accuracy. However, it is a risk to be dependent on a service that is controlled by one party. Especially when time distribution serves critical infrastructure as power gird. GPS is vulnerable to spoofing and jamming. For this reason, it would be ideal to have another backup time distribution method for GPS. PTP is a potential distribution method to be a secondary time distribution method for GPS.

PTP should be first tested alongside GPS. If PTP meets the requirements in real life, it could be the first priority time distribution method for Fingrid. GPS receivers could be used for the second option if PTP fails. In addition, GPS receivers at the substations could be used to measure the performance of PTP time accuracy at the substations. It should be noted that even with PTP, GPS is usually providing the time reference for the grandmaster nodes. Thus, PTP implementation may not necessary exclude GPS. However, there are a few other time source options, which are discussed in section 2.5.

2.4 Synchronous Ethernet

The reason why Synchronous Ethernet (SyncE) is discussed in this section, even it is not a time of day distribution method, is that it should affect positively to PTP performance. PTP can operate alone without SyncE, since if the system is time of day synchronized it means that frequency synchronization is also achieved. However, the synchronization would take much longer, especially if the system contains many nodes.

As said, SyncE is not a method to distribute time of day, it is a protocol for frequency synchronization across an Ethernet network. The basic idea of SyncE technology is to lock all the local oscillators in every node to the master or primary frequency reference. A SyncE device will take a reference frequency from its master, lock its own oscillator to the master frequency and transport that reference frequency to its downstream node. [36]

SyncE was introduced to tackle the issue of asynchronous nature of Ethernet network. SDH and PDH are circuit switched networks based on TDM (Time Division Multiplexing) that requires frequency synchronization to work properly. A SDH network node, that has a different frequency compared to other nodes, causes an overflow or underflow of data in its buffer. It results that the data samples will be lost or repeated to keep the bit rate constant. Traditional ethernet network was designed to send asynchronous data traffic. There was no need for synchronization with no losses of data. However, the applications of Ethernet may need synchronization to work, which SyncE provides. SyncE uses the physical layer interface to transfer frequency from node to node in a similar way as in SDH. [36]

The reason for slow frequency synchronization with PTP is that it sends PTP messages in relatively low frequencies, e.g. typical rate is between 16 times per second to ones per two seconds. In comparison SyncE has a line rate of 1 Gbit/s or

10 Gbit/s. Additionally it should be considered that in a PTP synchronization chain with boundary clocks, a downstream device cannot be synchronized before all the upstream BCs are synchronized. Thus longer time distribution chain prolongs the duration of synchronization. With a rough evaluation, this results that PTP without SyncE takes hours to synchronize, while with SyncE it would take minutes. With transparent clocks the synchronization process would be faster, because TCs do not have to synchronize their own clocks. [35]

After the synchronization is achieved, there is no information whether PTP performs better with SyncE. Nevertheless, SyncE is recommended to implement with PTP especially with systems with long synchronization chains and requirement to recover fast.

2.5 Time source

Each time distribution protocol has a source for the time signal it forwards to the applications. Distribution protocol defines how well it can maintain the accuracy it receives from its time source, but the time source defines the accuracy level that time distribution protocol tries to maintain. A grandmaster (GM) clock locates between a time distribution network and its time source. Next, we will go through three potential time source options for a GM: a GNSS receiver, an atomic clock or time source as a service from a third party. Table 2 presents three time source options and their characteristics.

Table 2: Time source options

Time source	Price	UTC	Pros	Cons
GNSS	Low	Yes	Easy implementation	Vulnerability
Atomic clock	High	Possible	Security	Requires maintenance
Third party	Unknown	Yes	Professional service	No previous experience

GNSS receiver is high accuracy and low cost option. However, GPS phase signals are not as stable compared to phase signals from a high quality atomic clock. Stable phase signal correlates to better time of day accuracy. Time from GNSS is locked into UTC time and therefore it allows comparison between other third party systems that are UTC locked. GNSS problem is its vulnerability. GM should at least be capable of switching between different GNSSs in case of signal loss. [29]

Another option for a time source is an atomic clock. There are atomic clocks with different price range from expensive and accurate to inexpensive and inaccurate. The accuracy level a power utility needs requires an expensive and accurate atomic clock. Three common atomic clocks are rubidium, Cs and hydrogen maser. Rubidium is the cheapest one and is not suitable for power utility time source. Cs and hydrogen maser are proper options for a power utility, where hydrogen maser is the most expensive and accurate. Rubidium price range is in thousands of euros, where Cs and hydrogen maser are approximately one and two hundred thousand euros respectively. [29]

A private atomic clock is not UTC locked, thus it is not comparable to other UTC time systems. However, it is technically possible to steer the atomic clock to match UTC time with a service from national metrology authority. Owning an atomic clock is a competent option, if one wants to be in full control of the time source, and can afford it. It is recommended to acquire three atomic clocks instead of one or two in order to find out if one clock is failing. It is difficult to know whether the clock is feeding wrong phase if there are no reference clocks to compare. Additionally it should be noted that atomic clocks needs periodical maintenance such as calibration. [29]

Third option is acquiring time source as a product from a third party. In Finland MIKES metrology department offers a service where the customer can lock its SSU-GM to national MIKES UTC time. Additionally a customer can join MIKES UTC time with its own atomic clock to increase the reliability of the whole system and to be locked into UTC time. MIKES maintains national UTC time and they operate during office hours. In case of failures during out of office hours, it is important that SSU has proper holdover capability or alternative time source. Proper holdover time provides time to fix the first priority time source without interrupting the time service. [29] The time source as a service is a valid option with or without own atomic clocks. Its virtue is proper accuracy, UTC reference and independence from GNSS.

A grandmaster or master clock at the substation has internal oscillator. In normal conditions, they are locked to a time source. The time source can be any time signal the clock device uses for its synchronization. The oscillator accuracy is affected by temperature and aging. Temperature and aging do not cause significant error while the GM is connected to its time source, since the time source synchronizes GMs internal oscillator. When the time source is lost, GM internal oscillator starts to drift. Figure 10 illustrates how oscillator's time error increases without GPS synchronization and how the time error is disciplined by GPS time source. [30]

Characteristics of an internal oscillator defines how fast the time error increases when its time source is lost. The drift is slower if the oscillator is not sensitive to aging and temperature. Oscillator that drifts slowly will remain accurate for a longer period of time. The oscillator inside a master clock performs two main functions: it provides a stable signal for shorter periods by filtering possible fluctuation of its time source and for the periods when time source is not available it tries to maintain the accuracy within suitable limits. [30]

There are three types of oscillators: temperature compensated crystal oscillator (TCXO), oven-controlled crystal oscillator (OCXO), and rubidium atomic oscillator. Without time reference TCXO is able to maintain the time error within 1 μs for about 1-2 minutes while OCXO for 10-20 minutes and Rubidium for 8-15 hours. [30]

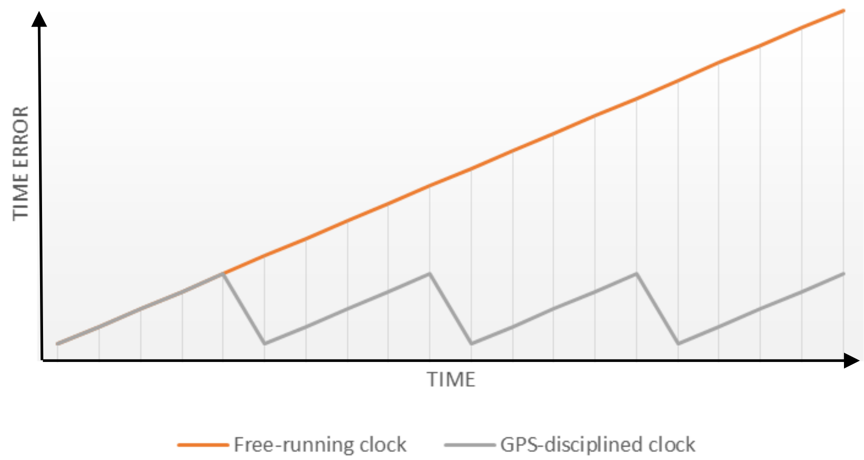


Figure 10: GM internal oscillator time error with and without a GPS time source [30]

2.6 PTP profiles

This section discusses profiles that concern PTP time distribution. PTP profiles are discussed because PTP is the most promising time distribution method and will be tested at Fingrid. Understanding PTP profiles will help to design PTP time distribution.

PTP standard IEEE 1588 defines a set of allowed PTP features to support precise synchronization of clocks. These sets of allowed features allows relatively much room for different kind of configuration. For more specific requirements to different network environments there are various PTP profiles that set more strict guidelines for the PTP devices. These profiles are variations of the main profile. Some profiles that presents restrictions to enable PTP in power domain are PTP Power profile, PTP Power utility profile and PTP Telecom profile. These profiles are discussed in this subsection.

PTP profiles modifies following features to fit better into the domains requirements:

- BMCA parameters
- PTP delay mechanism configuration parameters
- PTP management features
- default values of all the variable parameters
- PTP device types
- extra PTP features
- communication rules for PTP. [4]

2.6.1 IEEE 61850-9-3-2016 Precision time protocol profile for power utility automation, "Power utility profile"

IEEE 61850-9-3-2016 profile called as "Power utility profile" or "PUP" specifies PTP applicable to power utility automation. It belongs to IEC 61850 standard suite. Following description is not an exhausting list and more specific information can be read from the standard itself.

PUP aims to achieve a network inaccuracy better than $\pm 1 \mu s$ after 15 transparent clocks or 3 boundary clocks. This accuracy supports electrical substation applications such as precise time stamping of voltage and current measurements for differential protection, event recording, and wide area monitoring and protection. PUP supports time scales based on either TAI or UTC. Communication is done on Layer 2 over LAN or WAN Ethernet links. Link delay measurement uses peer-to-peer message exchange.

PUP operates with the default BMCA in case of singly attached clocks and doubly attached clocks shall support extension to BMCA defined in IEC 62439-3:2016. All network elements such as routers, switches, media converters (e.g. fiber to copper) and links are assumed to support PTP and they should have following accuracy performance:

- Grand Master: 250 μs
- Boundary Clock: 200 μs
- Transparent Clock: 50 μs
- Media Converter: 50 μs
- Link asymmetry: 25 μs. [31]

Additionally PUP allows a Parallel Redundancy protocol (PRP) and High-availability Seamless Redundancy (HSR) introduced in IEC 62439-3:2016. This protocol increases redundancy by allowing duplicated network paths and simultaneously active master clocks. Note that PUP is identical to IEC 62439-3:2016 Annex B, except that doubly attached clocks are optional in PUP. [31] [4]

2.6.2 IEEE C37.238-2017 Precision Time Protocol in Power System Applications, "Power profile"

Power profile specifies PTP applicable in power system protection, control and automation. It concentrates to consistent and reliable time distribution within substations and between substations. Power profile is compliant with Power utility profile and extends it with continuous monitoring of time inaccuracy, and optionally local time based on UTC. Power profile refers to PUP performance parameters. [6]

Introduction of the Simple Network Management Protocol (SNMP) and Management Information Base (MIB) allows key parameters to be monitored by standard network management tools. SNMP and MIB allows monitoring of time synchronization performance in real-time. PTP protocol uses the International Atomic Time scale (TAI) as a default time scale. Power profile includes an offset field to the PTP messages in order to convert TAI to UTC or any local time. TAI does not include leap seconds or other time discontinuities. Power profile requires peer-to-peer capability from all PTP nodes. It means that each device knows the path delays to their neighbor devices. [6]

Power profile allows the use of different physical layer communication technologies to carry Ethernet frames including SDH and wireless technologies if they can meet performance requirements. TCs uses P2P delay mechanism and the messages are transported over layer 2. [4]

2.6.3 IEEE G.8275.1/G.8275.2 Precision time protocol telecom profile for phase/time synchronization with partial timing support from the network

ITU G.8275 describes the general architecture of time and phase distribution using packet based methods using PTP standard. ITU G.8275.1 is a "Full Timing Support" profile and aims to build new networks for delivery of frequency and time. G.8275.1 requires boundary clocks with SyncE at every node in the network. It is based on point-to-point Ethernet Multicast. Accuracy requirement is 1.5 μs from grandmaster to the end application. [32] [33]

ITU G.8275.2 is a "Partial Timing Support" profile and aims to time and phase distribution over existing networks in unicast mode. G.8275.2 allows boundary and transparent clocks but does not demand them. Boundary clocks are placed at strategic locations to reduce noise. Additionally this profile introduces an alternative best master clock algorithm (ABMCA) instead of the default BMCA. One major change in ABMCA is that it allows multiple active GMs simultaneously. [34]

2.7 Redundancy

Redundancy and redundant system means in this context a system, which is reliable and will continue its function even if a component fails. Redundancy can be done e.g. by duplicating critical components and functions. Telecommunication network serves critical power grid infrastructure, thus the telecommunication network itself is a critical infrastructure, which should be redundant. This subsection discusses about redundancy because a redundant network that forwards time distribution messages (PTP) increases the operational security and robustness of the time service.

IEC 62439-3:2016 "Industrial communication networks - High availability automation networks - Part 3: Parallel Redundancy Protocol (PRP) and High-availability Seamless Redundancy (HSR)" standard introduces two different redundancy protocols. PRP uses two independent Ethernet LANs, while HSR introduces a ring topology.

Other common redundancy protocols are Dual Homing Link Redundancy and Rapid Spanning Tree Protocol (RSTP). These other protocols recovers automatically, but there is a time gap when there is no communications before the recovery. PRP and HSR are seamless redundancy protocols, thus they do not have any recovery time. Seamless redundancy protocols have following characteristics:

- Network nodes have two interfaces: port A and port B.
- Sending node sends a frame always in both directions.
- Each node has the same MAC and IP address on both ports.
- Receiving node processes the frame that arrives first and discards duplicates.
- Redundancy protocol takes care of the duplicate frames.
- Transparent to application, devices not aware of underlying redundancy. [37]

Both PRP and HSR targets only LAN redundancy for the electrical substation process bus described in IEC61850 9-2. However, e.g. [38] proposes a solution for PRP over WAN. LAN serves time distribution inside a substation and WAN serves time distribution between substations.

In simplified manner, PTP can be designed to be redundant by building a pruned mesh topology, where loops are eliminated by BMCA algorithm. In case of one node fails there would be still an alternative route for time distribution. Additionally nodes can be boundary clocks that have a certain holdover capability. It means that if a BC does not receive any PTP signals its internal oscillator can maintain the accuracy for some time depending on its quality. Redundancy can be achieved also by offering secondary time source for each substation such as GNSS time.

3 Time dependent applications in power system

Telecommunication network connects the substations and enables the communication between substation applications. The time distribution method and its time source defines how accurate and synchronous time the substation applications will receive. It is necessary to understand how the applications work and how accurate time is required by each application. This section will be the framework for defining how accurate time should the telecommunication network offer. It affects to the telecommunication network device acquisition and design of the network.

This section answers to the question that how accurate time do the applications require, while the previous section answered to the questions, what are the protocols to distribute time and what is their accuracy level. In the following subsections, we will go through next time dependent substation applications: Phasor Measurement Units, Fault recorder, Differential protection, Traveling wave fault locator and Sampled values. Each application is discussed both in general and from Fingrid point of view.

3.1 Phasor Measurement Units

Modern power system is a large complex system. More interconnections between synchronous areas are being installed and the amount of renewable power production is increasing. Transmission lines are being pushed to their operational limits. Monitoring and control of the dynamic power system has become vital to prevent outages. Proper monitoring requires real-time synchronized information from different locations of power system delivered to a centralized location where the data is processed. Phasor Measurement Units (PMU) are used for this purpose. PMUs delivers synchronized phasor measurements for monitoring, estimation and fault detection. PMU is a metering device that measures synchrophasors. [19]

Accurate synchronized time from PMUs in different locations of the power grid is the key to effective real-time monitoring and control. In major events, like cascading faults leading to blackouts, PMU data also offers possibility to study in hindsight and analyze the causes of the failure. PMU data from different locations must be able to comprehend and correlate to the events happening. For this reason, PMU measurements are time stamped in high accuracy using a common time reference. Operation standards for the PMUs are defined in IEEE std. C37.242-2013 and IEEE std. C37.118.1-2011. [19]

PMU components and system

Figure 11 presents a possible layout of general PMU components and their relations. Synchronization module enables acquiring voltage and current signals in a synchronized manner with other PMUs in the network. This module can be an integrated GPS receiver, an input to an external GNSS receiver, or a PTP synchronization module. [12]

Conditioning circuit is an interface to voltage (VT) and current transformer (CT). Their analog signals are obtained by conditioning circuits. Voltage and Current

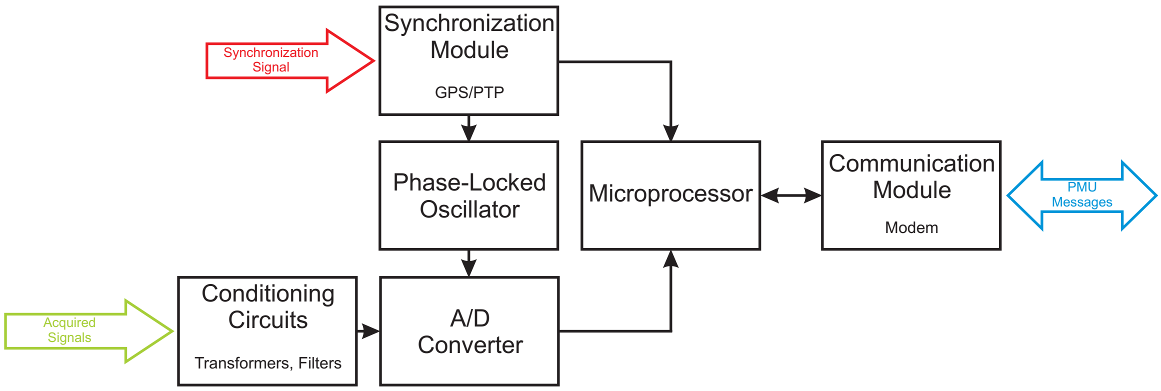


Figure 11: A block diagram of general PMU components [12]

transformers introduce uncertainty, which can be compensated if the transducers are accurately characterized. Usually maximum ratio error is limited to 0.5 % and a maximum phase error to 6 mrad for VTs and 9 mrad for CTs. VTs and CTs can be considered as the major source of uncertainty in a PMU. Filters are for attenuation of the input signals to meet the requirements of an analog-to-digital (A/D) converter block. [12]

Phase-Locked oscillator, which is synchronized by the Synchronization Module, synchronizes the PMU data acquisition. Data is acquired by sampling the signal from conditioning circuits and then sampled values are converted by the A/D converter. Microprocessor estimates all the current and voltage phasors and generates the time-stamp for the signals derived from the synchronization module. It can also derive other values from measured voltage and current samples such as frequency and rate of change of frequency. [12]

Communication module transmits the time-stamped data through the network to a Monitor Station or Phasor Data Concentrator (PDC) [12]. PDC is a device specially designed for receiving data from multiple PMUs and other PDCs and make their time alignment to create a phasor database. This database is transmitted to operation centers for applications that uses PMU data. PMU data transmission protocol is defined in IEEE C.37.118.2. [19] Figure 12 illustrates an example of a PMU system. Wide Area Network (WAN) connects Local Area Networks (LANs). LAN connects local PDCs and PMUs together and WAN connects Local PDCs and Monitor station together.

PMU and SCADA

PMU is often referred as a replacement or complementary technology for traditional Supervisory Control and Data Acquisition (SCADA) system. SCADA gathers measurement data from system nodes. The data contains voltage magnitudes, active and reactive power values, and system topology via breaker status. The breaker status information is close immediate, but active and reactive power is not.

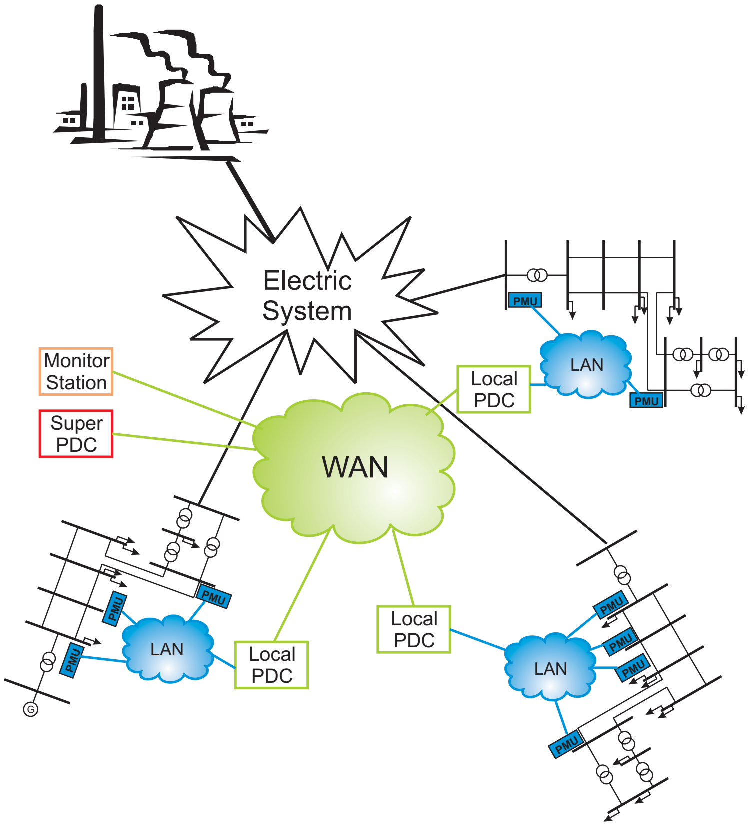


Figure 12: An example of PMU system topology [12]

The SCADA system periodically inquires data from remote terminal units (RTUs), protective relays and transducers. This query to retrieve the data lasts from two to 10 seconds and results to an asynchronous scan. During steady state situation, the long query duration is not a problem. However, rapid changes in the system state during the query could be undetected and the data no longer represent the system state accurately. System state justifying is called state estimation. State estimation is an operation that PMU measurements should improve compared to traditional SCADA measurements. [21]

As said, the current SCADA measurement mechanism is asynchronous and relatively slow. The asynchronous nature prevents comparison of phase angles between system nodes. Additionally the low data sample rate from RTUs may be too sparse to detect short-duration disturbances and present system state accurately. PMU offers a dynamic alternative method where phasors are estimated at the substation level with higher sample rate and high accuracy time stamps. [21] Phasor measurements enables voltage stability monitoring. Stabilization of large disturbances rely on phasor measurements of voltage and current offered by PMUs. [11]

In [21] Wide Area Measurement System (WAMS) including PMUs were tested and compared to traditional SCADA measurements. Measurements were done in Northern region of India at high voltage substations in real world situations. The

WAMS proved to be beneficial in the analysis of events and provided details of the system dynamics that were previously hidden.

Figure 13 presents frequency measurement results from PMU and SCADA. SCADA measurement presents an constant error of 70 mHz. PMU frequency measurement was validated to have an accuracy better than 1 mHz. From the Figure 13 it is also possible to see faster sampling rate of PMU measurements. PMU frequency measurements can be used to verify a proper operation of underfrequency relays, whereas SCADA measurements have too slow data rate for the validation. Currently utilities have to retrieve oscillography records from underfrequency relays or digital fault recorders to validate the operation of underfrequency relays. PMU measurements can also be used to verify the proper operation of df/dt relays (rate of change of frequency relay). [21]

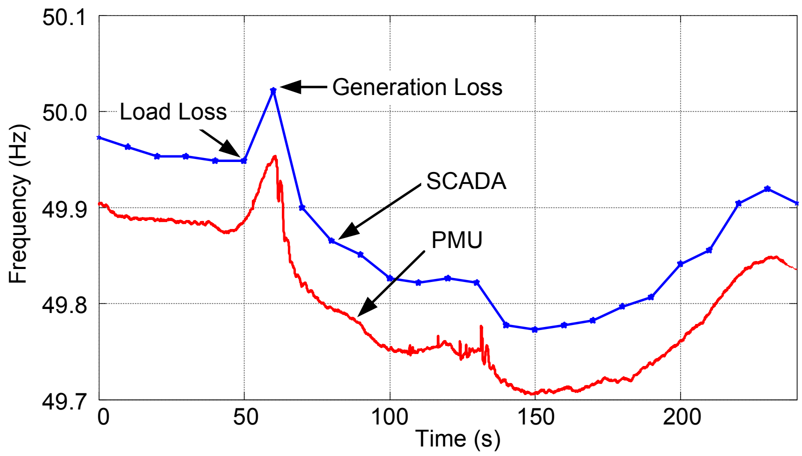


Figure 13: Frequency measurement done by PMU and SCADA. [21]

PMU applications

PMU itself is an application that requires accurate synchronized time. However, PMU measurements enables various functions in the power grid that are as well called as applications. These applications are divided into two general groups: real-time and off-line applications. Real-time applications are State estimation, Power Quality monitoring, Real-time monitoring and control of the power system, and Congestion management. Off-line applications are Post-event analysis and Validation of system models. [12] Four of the most relevant are further discussed below.

State estimation (SE) in power systems aids to understand the current state of the system based on the measurements of selected quantities. State estimator verifies that the received measurements are in accordance with current switching topology and laws of electrical engineering. [20] SE is a crucial task for the system operators since the system information is used to make decisions concerning grid operations. These operations includes e.g. voltage regulation, monitoring of the margin of stability, contingency analysis and dispatching. [12]

Traditional SCADA SE gathers system data such as active and reactive power flows, voltage magnitudes, and system topology from Remote Terminal Units (RTUs). SE with PMUs offers better quality compared to traditional SCADA measurements. One problem of SCADA SE is its poor time synchronization which results in poor quality SE. Proper time synchronization with PMUs enables comparison of phase angles between system nodes. Additionally to bus voltage measurements, PMUs are able to measure the current flows at the lines connected to the bus. However generally there are not enough PMUs installed to the power grid for full scale SE. Thus RTU based state estimation is more common technique. [12] Reason for low adoption of PMUs may be due to lack of trust to rely on GPS synchronization and the ability to run the system in a sufficient level with current SCADA system.

Power Quality monitoring is important to assess in liberalized energy markets. PMUs can provide data to find out the entities responsible for power quality (PQ) disturbances. One of the measures of PQ is based on harmonic state estimation which PMU data is capable to support. [12]

Real-time monitoring and control of the power system is essential for proper and efficient grid management. PMUs offer time synchronized system information simultaneously from different nodes. Therefore abnormal situations are noted immediately, which aids the system operators to make appropriate decisions to increase operational security. One important measure for operational security and stability that PMU data enables are phase angle differences between the system nodes. [12]

Post-event analysis is an important procedure after a disturbance and one of the first applications for which PMU was used. The data provided by PMUs from the power system nodes is in a chronological order. Chronological order aids to understand the source of the disturbance and the events that occurred after that. [12]

Other PMU applications that goes beyond visualization and postmortem analysis were mentioned in [21]. These included an automatic generation-shedding application based on synchrophasor measurements, and islanding detection and control.

Synchrophasors

The IEEE C37.118 defines the synchrophasors as "a phasor calculated from data samples using a standard time signal as the reference of the measurement". [12] PMU measures voltage and current of the power transmission line through a voltage and a current transformer respectively. Voltage and current can be represented as periodic sinusoidal signals. Periodic sinusoidal signals are commonly represented as phasors. A periodic sinusoidal signal in a time domain can be following:

$$X = X_m cos(\omega t + \phi) \tag{2}$$

Where X_m is the amplitude of the signal, ω is the angular frequency of the signal and ϕ is the phase angle with respect to a fixed reference frame. A phasor representation of a periodic sinusoidal signal is presented in the following equations:

$$X = \frac{X_m}{\sqrt{2}} e^{j\phi} \tag{3}$$

$$X = \frac{X_m}{\sqrt{2}} (cos(\phi) + jsin(\phi)) \tag{4}$$

$$X = X_r + jX_i \tag{5}$$

Where X_r and X_i denotes the real and imaginary parts of the complex value in rectangular components and $\frac{X_m}{\sqrt{2}}$ is the RMS value of the signal. [19] The waveform above in Figure 14 illustrates a periodic sinusoidal signal that PMU samples and measures. The waveform underneath illustrates a reference cosine signal which is synchronized to UTC time scale. The phase ω is defined to be 0° when its peak amplitude occurs at the reference time instant, and 90° when zero occurs at the reference time instant. Figure 15 presents these two phasor representations. [12]

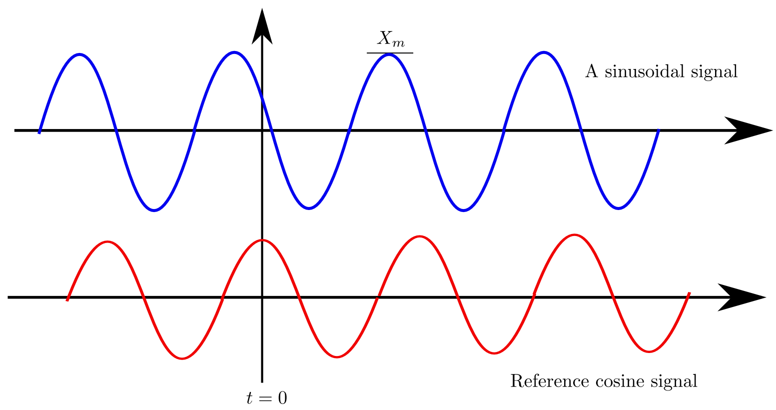


Figure 14: Synchrophasor representations with two different phase angles. [19]

The power system is a three-phase system. It can be presented by three different individual sinusoidal signals that are measured by a PMU. The phasors in a balanced three phase system have same magnitude but different phase angle ϕ. [19]

Importance of PMU time synchronization

Phasors from different locations across the power system can be put into a single phasor diagram, when all the PMU samples from different locations uses common time reference. This way grid operators can effectively monitor the states of the power system in real-time. For a large power grid, such a real-time phasor monitoring provides high resolution situation awareness of the grid. The time-stamps of measurements requires a high accuracy time source for each PMUs and the time distribution method has to provide time in a synchronized manner. [19]

A time skew in a PMU leads to an erroneous representation of the power grid and event reconstruction could provide false results. This kind of error has significant

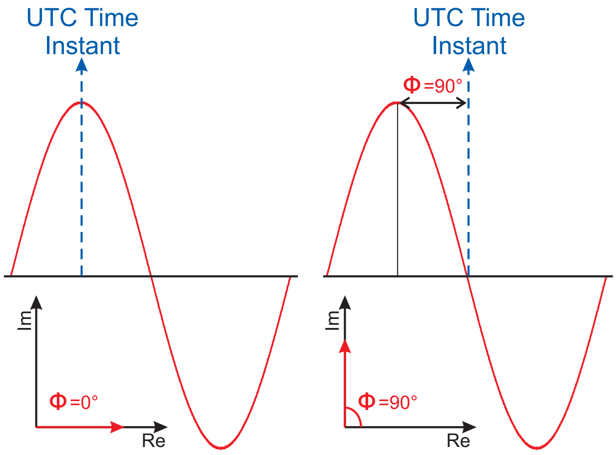


Figure 15: A sinusoidal signal representing power system current or voltage measured by a PMU and its time reference signal. [12]

negative effects if PMU data is used for control or protection. Figure 16 illustrates sinusoidal and phasor representation of PMU time sift away from accurate UTC time synchronization. It means that a sample for example of a line voltage value from place A measured by PMU A, which has a time shift, timestamps the sample. The sampled voltage value is in reality measured at a different time than the timestamp indicates. The sample is compared to samples from other PMUs with correct time stamps. This means that the PDC system assumes to compare voltages from different places at the same time but in reality, it compares samples that took place in different time. Comparing false information can lead to wrong actions and conclusions. [19]

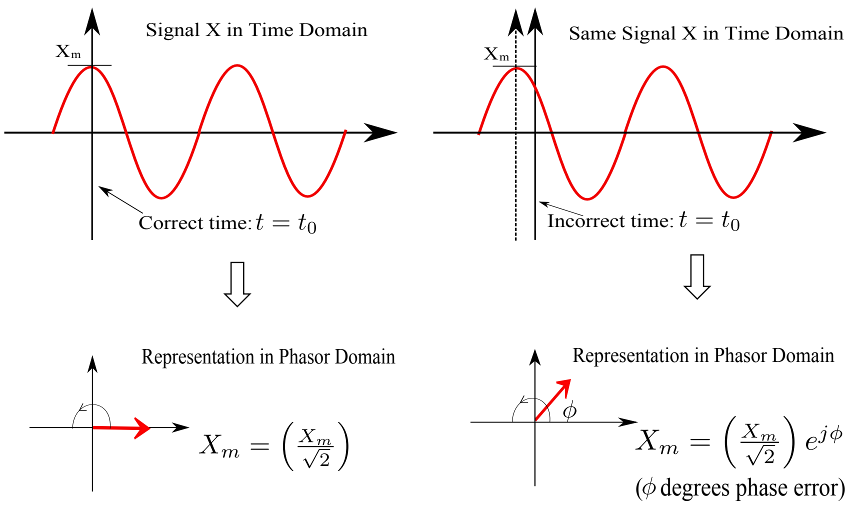


Figure 16: Time skew effect on PMU measurement. [19]

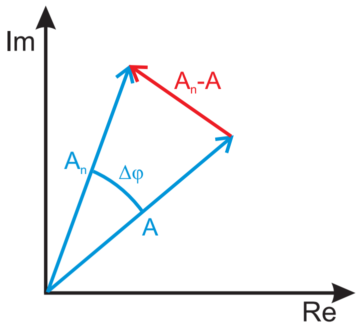
A time skew in PMU is caused either by internal or external synchronization error. Usually a PMU synchronizes its own oscillator by a PPS signal from a GPS unit. Thus every one second PMUs own oscillator receives a synchronization pulse. Between the pulses, PMUs own oscillator can start to drift and it is not possible to attain synchronization immediately by next PPS signals. This is called internal synchronization error, when the error source is the PMU oscillator itself. External synchronization error is caused by an erroneous synchronization signal received by a PMU. Either PMU can lose the timing signal or the timing signal itself can be incorrect. [19]

PMU measurement quality requirements are presented in the standard C.37.118. One of the concepts to evaluate PMU measurement quality is the Total Vector Error (TVE) calculation. The time synchronization signal received by a PMU should be accurate enough to keep TVE within statutory limits. TVE is defined by the root-squared difference between theoretical/actual phasor value of the signal and the phasor estimate of the signal measured by the PMU under test at the same instant in time. [12] TVE can be expressed as follow:

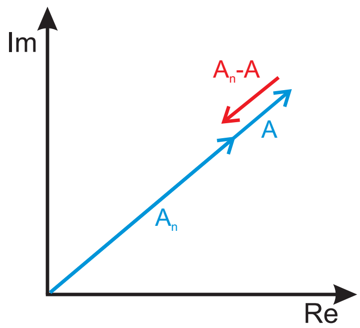
$$TVE(n) = \sqrt{\frac{(\tilde{X}_r(n) - X_r(n))^2 + (\tilde{X}_i(n) - X_i(n))^2}{X_r(n)^2 - X_r(n)^2}} \tag{6}$$

where $\tilde{X}_r(n)$ and $\tilde{X}_i(n)$ demonstrates the phasor representation of the measured synchrophasor, and $X_r(n)$ and $X_i(n)$ demonstrates the phasor representation of the actual phasor at the instant n.

IEEE standard C.37.118.1 allows maximum ±1% TVE. Regarding to Equation 6 time error of 31.8 μs corresponds to the phase error of 0.573° and again to a 1% TVE with system frequency of 50 Hz. In addition to the phase error, TVE includes magnitude error. This means that if there is a magnitude error it leaves less budget for the phase error and again for the time error budget. Thus, when TVE indicates an error of 1% it is not known if the error consists of phase, magnitude or both. Figure 17 illustrates this challenge.



(a)



(b)

Figure 17: TVE caused by phase (a) and magnitude (b) [19]

Nevertheless, the quality of measurement suffers from time error. PMU time synchronization signal should be accurate enough and available constantly. For PMU to meet the 1% TVE requirement, the absolute time accuracy requirement for the time source is $\pm 31.8\mu s$. This accuracy requirement is possible to reach in theory with IRIG-B, GNSS and PTP time distribution methods.

Phasor Measurement Units in Fingrid

Now Fingrid owns approximately 15 PMUs located at critical nodes of the Fingrid power system. PMUs are connected by IRIG-B connection to GPS units. Fingrid owns a PDC where each PMU is connected to the MPLS network. Fingrid PDC is connected cross borders to other PDCs owned by Swedish, Norwegian and Danish Transmission System Operators. These other PDCs collects phasor data from their national power transmission grid. National PDCs shares the phasor data, thus each TSO has phasor data from every country in the Northern Europe synchronous area. [23]

Fingrid's PDC does time alignment of the phasor data and forwards it to different visualisation software. System operators at Fingrid uses traditional SCADA for all major control and monitoring purposes. Fingrid SCADA measurements do not offer phase angles and the data from different nodes is not synchronized. Thus the system operators uses PMU data visualization software to check accurate and synchronous phasor data when SCADA measurements looks alerting or there are some other reasons to further understand the system state. [23]

Fingrid's other professionals investigates PMU data which is alarmed to indicate for events of their specific field of interest. Phasor data is useful for observation of oscillations, network transmission capacity and voltage stability calculations.[23]

At the moment there is no specific plan for further PMU investments, although it is seen that the amount of PMUs will increase. SCADA system will not be replaced by PMUs anytime soon. Major reason for that is SCADAs ability to control the power system, which PMU is not capable. PMU data would be possible to include in SCADA. However, so far the decision has been to keep SCADA and PMU measurements in their separate systems.[23]

PMU data quality is on a sufficient level for most of the time. There is no specific observation of TVE. Errors in PMU data is noticed when the data is observed and the person who observes notices abnormalities. Abnormalities are noticed relatively often. Experience reveals that for most of the cases there is a problem with PMU GPS time reception. If there is no time stamp, PMU will not forward the data or it's quality is too poor that PDC does not allow it. Generally, PDC waits for one second to receive data from PMU. Total loss of GPS signal is easy to notice when the data is missing. Trickier is a time error which is not filtered by PDC. In that case, it is difficult to know the root reason for the abnormality. Additionally it is possible that one does not even notice the existing error. [23]

GPS time accuracy itself is on a sufficient level for Fingrid's needs. However, time distribution offered by Fingrid telecommunication network would be an improvement if the time source is reliable and continuous compared to GPS, and close to GPS accuracy within microsecond level. In this case, there would be less abnormality in the PMU data and further no more need to investigate whether the problem is in the time source. This would increase the data quality of PMU measurements and the trust for PMU technology, which could lead to faster adoption of PMU technology and applications relying on it. [23]

3.2 Fault Recording

A disturbance at one point in the power system effects to the operation elsewhere and in worst-case scenario can lead to cascading faults and blackout. Disturbances cause abnormal values in measured quantities and events in relay logs. Fault recorder enables a proper interpretation of the disturbance and its effects by offering the fault data it gathers. Additionally fault recorders can be used for evaluating protection system performance by gathering data of relays, circuit breakers, and control systems. As a result, it is possible to calculate fault locations and understand the sequence of events that happened and improve the design and profiency of the power system. [22]

Fault recorders (FRs) and microprocessor-based relays provide measured waveforms of selected quantities and sequences of events. Compared to microprocessor-based relays, FRs generally have higher sampling rate, processing power, larger lengths of records, and are able to record wide system response. Additionally some micro-processor-based relays use digital filters that do not reflect the real captured waveform. [22]

FR can be configured to begin recording from different kind of triggering events, generally independent from relay response. The most common triggering are for zero sequence currents and under-voltage. Usually the record itself contains samples just before, during and after the triggering event. In a FR, these times are often defined as pre- and post-triggering time. The record length can be presented either in cycles of waveform or seconds. Fast transients has generally pre-triggering of 60 cycles and post-trigger time of 1800 cycles (30 sec with 60 Hz). Swing records has generally pre-trigger time of 60 seconds and post-trigger time of 1800 seconds (30 min). [22]

Sequence of events gathers binary data from relays and breakers, which tells if the relay has picked up or triggered, or the change of status of a breaker opens or closes. Trip surge coils offer specific "trip coil energization time", which enables analyzing if a breaker is interrupting the current at an adequate time. Analog waveform of current and voltage comes from current transformer (CT) and voltage transformer (VT). FR software can derive from CT and VT analog inputs different visualizations such as normal sine waveform, symmetrical components, and phasor diagrams. Symmetrical components are used to decipher types of faults. Phasors diagrams aid to distinguish and visualize fault behavior. Current and voltage information is used to calculate fault location. In addition, the analyst can compare the measured values of fault situation to calculated values for possible inconsistencies. [22]

System event records are divided into two categories: fast transient recordings and slow swing recordings. Fast transient includes fast system events such as power system faults, lightning strikes, switching events and insulator flashing. This type of faults are short-lived, thus they do not need long record length. Fast transient records includes current and voltage magnitudes, time, and duration that was used to observe the event. Slow swing recordings captures the power system's response in RMS values triggered by a power swing or disturbance. Slow swing records can capture the response of generators, power swings on transmission lines, load variations caused by voltage and frequency fluctuations, and transient phase angle changes. Swing records do not have fast rise times, thus it does not require high sampling rate. Studying of swing records requires putting together data from many FRs and therefore needs accurate time stamps for the samples. Slow swing records captures much longer periods of records than transient recordings. [22]

Time synchronization requirements

FR information is used to calculate fault location. There are various methods to calculate the fault location and one of them is a current-ratio method, which is based on impedance calculation. This method requires synchronized phasor information from both ends of the faulty transmission line. It means that the FRs must be time synchronized, otherwise there will be an error in the result. [25]

Investigation of wide area disturbances can be time-consuming and laborious. Investigation is faster if the samples from different fault recorders are time stamped from the same time source. In August of 2003, North America experienced a major blackout. The investigation and analysis of the 2003 blackout was difficult and time-consuming since the fault recorders were not properly time synchronized. Due to this incident, The North America Electric Reliability Corporation (NERC) began to require time synchronization within 2 ms or less from UTC time for fault recorders. FRs are generally synchronized by IRIG-B signals derived from a GPS unit. PTP offers time synchronization with sufficient accuracy for FR. PTP should offer synchronization within microseconds. [22]

Fault recorders in Fingrid

Fingrid uses FR for interpretation of fault situations, calculating fault location and examining if relays are functioning properly. Fault interpretation consists of current and voltage waveforms and sequence of events. Only fast transients are recorded by FR, slow swing effects are examined from PMU data. [24]

Fingrid owns approximately 90 FRs. Since there are more than one hundred substations, not every substation contain FR. Basic principle for FR implementation at the substation is if the voltage level is 400 kV or there are at least five feeders. One substation can have one to three fault recorders. A basic FR has one or more modules that contain analog and binary inputs. There are usually 16 analog inputs and 32 binary inputs in a module. The FR may have more than one module, but usually the maximum total amount of analog inputs is 64, which means 4 modules. The amount of analog and binary inputs dictates from how many feeders can a FR gather data. [24]

One feeder requires three analog input for the phase currents and one for the zero current. Voltage is measured from the bus bar voltage transformers. Voltage measurement requires three analog inputs for the phase voltages and optionally one extra for the zero voltage if it is not derived by a software from the phase voltages.

Binary inputs receive yes or no (binary) information from the circuit breaker trip and relays. A binary input can represent for example pick up or trip of a distance relay.[24]

FR data is examined in a disturbance analysis system named STINA. STINA collects fault records (COMRADE-format) from protection relays and FRs. Fingrid FRs are connected to the STINA server through the MPLS network. Fault information (e.g. fault type, calculation algorithm, and fault values like zero currents and phase voltages) from STINA is forwarded to IBM Maximo asset management software, where the FALO application calculates the location of the fault with the aid of PSSE network model. When the fault location is known, it is possible to send patrol group to examine the possible damage to the transmission line. [24]

Most of the FRs are time synchronized from RTUs. RTU sends the time information to the FR once in every minute with worse than millisecond accuracy. Time synchronization from RTU requires an external synchronization device in between which causes errors and regularly decreases the millisecond time accuracy. Recently there has been a few substations where the fault recorder receives time synchronization from an NTP server through the MPLS network. It has proven to be a sufficient solution. NTP through MPLS tackles the problem of the error sources caused by RTU and synchronization device. Fault Recorders can generally receive many kind of time synchronization protocols such as IRIG-B, SNTP and PTP. GPS time can be distributed through IRIG-B signals. [24]

Current millisecond accuracy level is sufficient for fault interpretation. Accurate time stamps are not needed when fault information is examined only within one substation. Time stamps of millisecond accuracy level are needed when there is a need to compare fault information from two or more substations. This is the case when the fault location is calculated by the current ratio method. Current ratio method requires synchronized time sampled data of currents feeding fault from both sides of transmission line. Poor time synchronization results to wrong fault location estimation which again leads to more work hours spent searching the possible damage site along the actual transmission line. [24]

Time synchronization of fault recorders enables also interpretation of sequence of events happened at different substations. Additionally it would be beneficial if fault recorders would have the same time source than protection relays. This is because often information from both applications are compared. Even when RTUs offer time for both relays and fault recorder, there are time errors between the measured events. [24]

Thus, Fault recorder needs reliable millisecond time accuracy synchronized with other fault recorders and protection relays. NTP time through MPLS network has proved to be sufficient, which means that technically also PTP protocol could deliver the time. PTP accuracy is in theory better than required. Additionally, advantage of PTP and NTP is that they use the same Ethernet connection as other data, thus they do not require any dedicated time cabling. [24]

3.3 Differential Protection

The most common line protection relays are distance, differential and earth-fault relay. Distance and differential relays are the only ones to use telecommunication. These relays need to communicate between each other when they are located at the both ends of transmission line. Communication latency for both protection types should be as short as possible and predictable. Additionally, differential protection requires high accuracy and synchronization to function. However, for distance protection, time synchronization is not crucial and that is why it is not further discussed here. On the other hand, all relays benefits of accurate and synchronized time to have a proper time alignment in their event logs. Then event logs are easier to compare with other devices' event logs both on the same and remote substations. This helps the fault investigation process.

Differential relay is used for line, transformer and bus bar protection. In here, we discuss line differential protection, because that's when time synchronization may be needed. Differential relay functions when the sum of the currents flowing in and out the protected area exceeds the relay threshold value. The sum of currents is zero, when there is no faults inside the protected area, because then current flows through the area. When there is a fault inside the protected area, current does not flow through, but fault currents from outside the protected area flows inside. Thus, the sum of currents is not zero anymore and differential relay opens the circuit. Differential protection protects only an area that current transformers covers and their measured values are compared. [26] Figure 18 presents the basic idea of line differential protection.

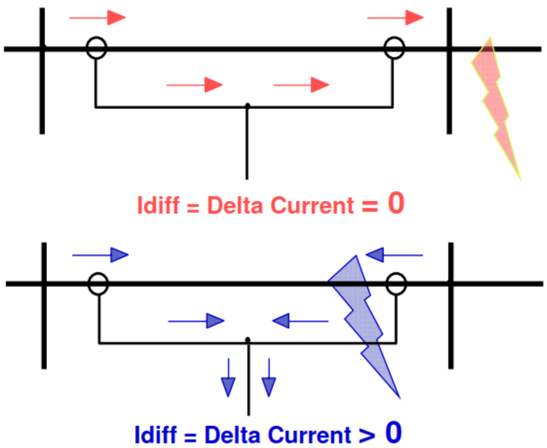


Figure 18: Line differential protection basic idea [4]

Line differential protection requires communication between the differential relays located at the transmission line terminals. If the distance between relays is short, a separate connection can be made. If the distance between relays is long, existing telecommunication network is used. Connection can be made either by optical fiber or radio link.[26]

The communication network between relays has traditionally been SDH network. SDH is based on TDM (Time Division Multiplexing), which provides symmetric communication delay in both directions. Symmetric delay is utilized to achieve time synchronization between the protection devices. In [4] and in [27] IP-based packet swiched network was succesfully tested for differential protection. Motivation towards packet switched networks is more efficient utilization of the available bandwidth, requirement of fewer network devices and connections for the same network load. Additionally SDH is becoming outdated and is replaced by new Ethernet/IP based network technologies. Thus, there is a need to find an alternative method for line differential protecting relays to communicate such as packet switched network. [4]

Time Synchronization Requirements

Line differential protection (LDP) is based on comparing current values from different locations at the same moment. Comparing samples at different time instant while assuming they are at same time instant can cause spurious differential trip. There are two methods to ensure comparison of samples at the same instant. First one is relays with time stamped current phasors when relays on both stations are synchronized to the same time source. Another one uses asymmetrical sampling, which is better known as ping pong or echo delay measurement method. The echo method is required when there is no time synchronization between substations available. [27]

Low latency, latency symmetry and low jitter are important measures for LDP. Though only latency matters if substations are time synchronized by GNSS. However, in most schemes GPS synchronized systems are configured to fallback to asynchronous sampling in case of GPS signal failure. Latency asymmetry and jitter impacts significantly on line differential operation when asynchronous sampling is used. Latency presents the time it takes for the samples to make across to the remote end for comparison. Thus, it affects directly to the time it takes for the relay to detect the presence of a fault. Jitter means variation in the latency. [27] IEC standard 61850-90-1 recommends latency and jitter values for the communication. General requirement for latency is between 5 ms and 10 ms. [4]

A sufficient time synchronization accuracy for time stamped phasor values for differential relays is in sub millisecond level. [4] presents synchronization requirement of less than 10 μs and [11] says fair time synchronization error is within the limits of 100 μs. PTP and MPLS would be a sufficient combination and has been tested in [4].

Line differential protection in Fingrid

Fingrid uses LDP in places where selectivity is difficult to obtain with distance protection or where distance protection is not applicable. Selectivity is the case at short lines or when there is a parallel circuit, and for series compensated transmission lines, distance protection is not fully applicable. In these situations, LDP is the main protection method and there is no other reasons to use LDP in Fingrid. In general, distance protection is more common in Fingrid compared to LDP, however the places LDP exists, it is crucial for the operational reliability. LDP protection in

Fingrid is based on asymmetrical echo method. It is done by either straight fiber connection or through SDH network. [28]

A Differential relay at a substation is connected to a current transformer by four analog inputs: 3 phases and a zero current input. E.g. Differential relay A transforms analog signals into digital samples and sends them to differential relay B which measures current from the other end of the transmission line. Then differential relay B compares the received current measurement sample to its own sample from the same moment. The comparison happens vice versa in relay A and is repeated by both relays continuously. Echo method enables relays to take the latency of the telecommunication into account. Asymmetry in latency causes inaccuracy to the latency estimation. Differential protection area in Fingrid generally consists of one transmission line without branches, thus there is communication only between two differential relays. [28]

With current asymmetrical echo method there is no need for accurate time for LDP. However, LDP could benefit from a reliable, synchronized and accurate time source for the relays. If, in the future, LDP would be based on synchronized time stamps, it would still need a possibility to fall back to asymmetrical echo method. This is because, if LDP does not function properly, it causes unnecessary tripping and leads to financial losses and gives negative reputation for Fingrid. [28]

Currently LDP expects with echo method that the compared current samples are within 0.5 ms error margin. Thus, there can be 1 ms asymmetry in latency. It allows sampling time synchronization error of 0.5 ms between relay A and B and still relays do not break the circuit. This error margin is relatively high, which means that the sensitivy is set to a low level, and thus, it is difficult to detect high resistance and low current faults or phenomenon. A high resistance fault could be a tree touching transmission line, which causes low fault current. Differential protection cannot detect a tree fault if the sensitivity is set too low due to the lack of trust how accurately the samples are compared. [28]

Another example of a problem with low sensitivity is detecting capacitive current, which is substantive at long transmission lines. Capacitive current exists at transmission line even if there is no load connected. Additionally it means that there is always a difference in currents that are measured in line ends. Thus, capacitive current has to be compensated in relay settings in order to avoid unnecessary tripping. Now the problem is that capacitive current combined with time errors in measured current samples leads to low sensitivity settings. If the synchronization of measurements could be trusted with better accuracy, Fingrid could configure accurately the compensation of capacitive current and again increase the sensitivity of differential protection. [28]

The accuracy requirement from Fingrid point of view is in line with the requirements found from literature. Tens of microseconds should be a sufficient accuracy level. In addition to high accuracy and reliability, latency has to be in a sufficient level. The protection usually has 100 ms time from the beginning of a fault to open the circuit before the fault causes damage for other components. The time for relay to open the circuit consists of communication latency, relay operation time and breaker operation time. Therefore, it is better that communication latency would be as short as possible. Latency should be evaluated especially if measurements are taken into an MPLS route, which could be longer than a direct fiber connection. Latency should be as low as possible and predictable. 10 ms latency is already a high value and should be preferably lower. [28]

PTP and MPLS could be a sufficient solution for Fingrid LDP. PTP is accurate enough. The most important issues to tackle are guaranteeing high reliability and low latency. Additionally it should be possible to detect a faulty situation if for example synchronization accuracy decreases. After fault detection relay should automatically fall back to the echo method and decrease sensitivity settings in order to prevent possible false tripping.

3.4 Traveling wave fault locator

There are a few common methods to find the fault location from a transmission line. One of them was discussed in the section 3.2 where fault recorder data was utilized. Another method is traveling wave based fault location technique. Traveling waves are transients in the power grid. E.g., faults, circuit breaking and lightning strikes causes transients. [25]

Traveling wave proceeds to both directions from the fault location with a pace close to speed of light c. The grid structure does not affect to the propagation speed, though every point of discontinuity causes a reflection. Figure 19 illustrates reflections of a traveling wave. A device called Traveling Wave Fault Locator (TWFL) detects traveling waves and its reflections. TWFL then time stamps each reception of the wave and with the known speed of propagation calculates the fault location. There are five different methods to calculate the fault location by TWFL. Depending on the method used, there has to be a TWFL in the one end of transmission line or both. Methods are divided into one-end methods and two end methods respectively. Descriptions of these methods can be found from [25]. Now we will discuss of the two-end method which Fingrid uses.

The two-end method that Fingrid uses requires measurements from both sides of the fault location. However, TWFL do not need to be directly at the end of the same transmission line where the fault occurred. Centralized calculation technique can take into account multiple lines between the two devices. TWFL time stamps the arrival of the traveling wave at the both sides of the fault. [25]These timestamps are in the Figure 19 presented as t_1 and t_2. Time difference Δt of the timestamps t_1 and t_2 is calculated in a centralized manner and by knowing the propagation speed v_p of the traveling wave and the length L of the transmission line, it is possible to calculate the fault location x with the following Equation:

$$x = \frac{L + v_p \cdot \Delta t}{2} \tag{7}$$

Time synchronization requirements

TWFL is based on measuring the propagation of a traveling wave, which has a pace close to speed of light. If TWFL uses one end method, it does not need synchronization

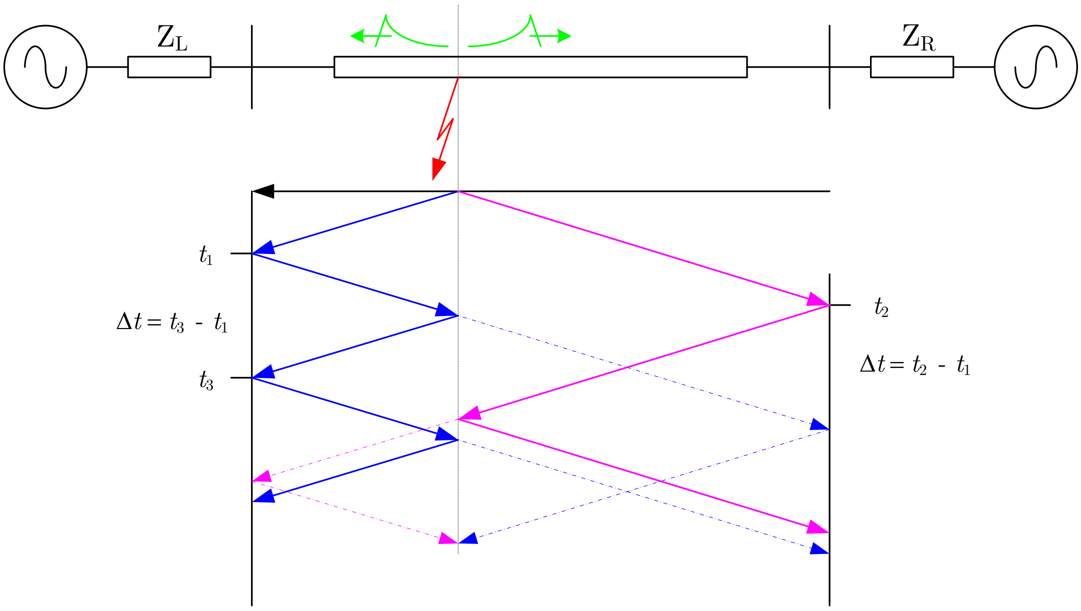


Figure 19: Reflections of traveling wave [25]

between substations, but it requires high accuracy clock. Measuring events that happens almost in speed of light require extreme accuracy. Light propagates 30 m in 100 ns. If one time stamp has a time error of ± 100 ns, it results to a ± 30 m calculation error. Both one end and two end methods requires two time stamps, which leads to an error of ± 60 m with ± 100 ns accuracy. However, this result is still divided by two as in Figure 7 when the actual fault location is calculated. [25]

In the case of the method that Fingrid uses, not only the accuracy of TWFLs clock matters, but also synchronization between the TWFLs'. Time synchronization between TWFLs is generally done by GPS receivers. GPS should offer time accuracy everywhere with an error smaller than ± 1 μs. Thus in theory a TWFL with GPS synchronization detects the fault location with a maximum error of ± 300 m (300 m error from each two time stamps divided by 2 as in Equation 7). In practice GPS synchronization and TWFLs usually performs with better accuracy and some of the suppliers promises a maximum error of $\pm$ 60m. [25]

TWFLs in Fingrid

Fingrid owns 40 TWFL devices. The devices cover 400 kV transmission lines and in Northern Finland 220 kV and 110 kV transmission lines. Fingrid plans to install more TWFLs to cover the whole transmission system in near future. TWFL is at the substation connected to the current transformer by an analog input to each three phases. TWFL sampling frequency is 20 000 MHz and the measurement duration beginning from fault occurrence is configurable. [24]

TWFLs provides usually more accurate fault location estimates than e.g. fault recorder. Therefore, TWFL saves the time of a patrol group to search the fault location. TWFLs are additionally capable to detect malfunctions in components before final degradation. This is because TWFL is able to detect high frequency phenomenon that e.g. an insulator degradation causes. In some occasions, fault recorder is not able to provide proper fault location results while TWFL is capable. During an earth fault, there is a low zero current in the transmission grid with high reactance and hence fault recorder cannot locate the fault. Also transmission lines with series compensation causes difficulties for fault recorder to locate a fault. Series compensation misleads fault recorder's impedance based calculation if the fault is behind the series compensation.[24]

Fingrid uses the two-end measurement method for fault location estimation. One end measurement method is used only in situations when the TWFL in the other end is not functioning properly, e.g. if there is no GPS signal available. One end method is problematic since the reflection (t_3 in Figure 19) from the fault point is difficult to distinguish from branch and other discontinuity point reflections. Two-end measurement method does not have this problem because it needs to measure only the first traveling wave on both ends. Additionally the two-end measurement method is automatic, which is a significant advantage and improves the speed of fault recovery process. In the case of one end measurement, Fingrid operator has to manually set the second reflection point to its correct place on the measured waveform in IQ+ software. [24]

The software runs fault calculation in a central server based on the information fetched from TWFLs. Thus, TWFL does not inform the fault location but provides the measurement data for IQ+ software through the MPLS network. Data includes time stamped waveform, which IQ+ uses to calculate the fault location automatically if information is provided from both ends. In near future Stina software will fetch fault location information from IQ+ to reduce the amount of software the operators has to use in Fingrid. [24]

Poor time synchronization results to poor evaluation of fault location as it can be seen from Equation 7. Fingrid TWFLs requires accurate time synchronization while reliability is not as important as it is for differential protection. However, there are typically financial losses if fault location is not evaluated or it is evaluated inaccurately. Fingrid uses GPS receivers to obtain time synchronization between TWFLs'. TWFL devices are capable to support an accuracy of 100ns which equals $\pm$30 meters error in calculated fault location. GPS has even better accuracy than 100 ns with fairly good reliability. [24]

Additionally to a time synchronization error, the cabling from the CT can cause an error in calculated fault location. [24] If the cabling at both substation is equal, there is no error. Otherwise, there will be an error of half of the difference between the length of cabling at the substations. E.g. if the cabling length at a substation A is 0 meters and at a substation B 400 meters, it results to 200 m offset at calculated fault location. This can be detected from Equation 7. This kind of cabling cannot be compensated by configuring the TWFL. Thus, time synchronization error is not the only error the TWFL fault location estimation includes.

PTP would offer 1 μs or better accuracy with high reliability. GPS accuracy is better than the accuracy of PTP. In theory GPS estimation is $\pm$270 m more accurate. There is no proper reason to use lower accuracy time source if there is a better one available. Fingrid wants to have as less as possible error in their fault location estimation caused by the time source. However, PTP with 1 μs accuracy is good enough to be a secondary option for GPS. In cases that GPS signal is disturbed or not available, an option to use PTP instead as a backup would be beneficial. Unfortunately, current TWFL devices in Fingrid do not support PTP protocol. Until there is no support for PTP from the device, the time signal should be transformed from PTP to IRIG-B, which should have an accuracy close to PTP. [24]

3.5 Sampled values

Sampled values is not a similar application than FR, TWFL or LDP, but it is a technology that supports other applications by providing them data. Sampled Values has an important role in the new Ethernet based IEC 61850 substation automation.

Sampled values provides real-time instantaneous voltage and current measurement data streams for protection, monitoring and control. Digital secondary system requires only one fiber link from each NCIT to a Merging Unit, which distributes the sampled values to the applications, such as relays. This kind of digital secondary system setup reduces the need for multiple copper cables from instrumental transformer individually to each application.

Merging unit requires accurate and synchronous time in order to produce reliable samples and to keep up with the high sampling rate (4 to 16 kHz). A proper time synchronization is important especially when there are protection applications relying on sampled values (e.g. LDP). A 30 μs time error equals to a half degree phase angle error. The demanded time synchronization accuracy is less than 1 μs. [11] Sampled values are not used in Fingrid, however in the future they may be applied together with ongoing digital substation project.

3.6 Summary of time dependent applications

Table 3: Time dependent substation applications

Application	Time requirement	Critical	Requires low latency
PMU	<32 μs	No	No
Fault Recording	1 ms	No	No
LDP	10 μs	Yes	Yes
TWFL	1 μs	No	No
Sampled values	1 μs	Yes	Yes

Table 3 presents all the applications that were discussed in previous subsections and their accuracy requirements. Time distribution should be designed to be as accurate as the most demanding application. In this case the accuracy target would be 1 μs. Criticality means that if the application does not work properly, it affects directly to electricity transmission. However, even if an application is not critical it does not mean that it is unimportant.

Additionally there are a few more existing applications that rely on synchronized time in addition to the 5 applications listed on Table 3 above. However, the rest of the applications are not relevant for Fingrid at the moment, do not require high accuracy or they do not add any additional value for this thesis. More applications can be found in [11]. It is also likely, that after there is reliable, accurate and synchronous time offered to each substation, the amount of time dependent applications in Fingrid will increase.

4 Appropriate time distribution technology for Fingrid and its accuracy

In this section, I gather together all the previous information and answer to the thesis questions. First, the time accuracy requirement for Fingrid is answered. Then we go through possible scenarios for selecting the time distribution method. After that section 4.3 proposes how time distribution should be done in the future. Finally, there is a list of aspects that should be taken into account in time distribution implementation and its significance for transmission reliability.

4.1 Fingrid's applications and their accuracy requirements

This subsection discusses the Fingrid perspective of time synchronization requirements. More thorough investigation can be found in section 3. After understanding the need for time synchronization, it is possible to make an optimal decision about the time distribution method Fingrid telecommunication department should implement. Accuracy requirement from the application point of view is ± 1 μs. Fingrid has currently four applications that relies on accurate and synchronous time. These are: PMUs, Fault recorders, Differential protection and Traveling wave fault locators.

PMUs uses GPS receivers for the synchronization. 32 μs is the standard minimum accuracy requirement for TVE. However, it does not leave any room for magnitude error and thus the time error should be lower than that. GPS is easy to disturb, thus it cannot be trusted even it would happen rarely. This is one reason why PMU potential has not fully utilized, and it is mostly used for post analysis. Yet PMU offers valuable phase angle information, which is not available in current SCADA system. With trustworthy time synchronization, PMUs could be adopted better for real-time system monitoring in control rooms. On the other hand, this is also a commercial question. There should be a SCADA integration with current system or a parallel system to take advantage of PMU information. Nonetheless, PMUs could be trusted better with a new reliable and accurate enough time distribution method.

Fault recorders compares impedance values from both ends of a transmission line. From that information fault recorder derives the fault location. Fault recorders also have an event log, and data samples of currents and voltages from system events, which are useful information for post fault investigation. Now fault recorders receive time synchronization with accuracy between 1 ms to 100's of ms. 1 ms accuracy is already acceptable, fault location may not be extremely accurate but it helps. TWFL provides more accurate fault locations in the future which, tackles the problem. Accuracy of hundreds of milliseconds is relatively poor. It will already cause difficulties to compare fault data and event logs between other devices' data and event logs. More accurate time synchronization would add value for fault recorders.

Differential protection is the most critical application among the four applications mentioned here. Any malfunction in differential protection may lead to financial losses and larger damage in fault situations. In Fingrid, differential protection mainly uses an asynchronous echo method to reach synchronization. Thus, there is no need for time of day synchronization. It only requires an accurate enough clock for both ends and a straight fiber connection between them. If differential protection would communicate through MPLS network, it would require synchronization accuracy of somewhere around 10 μs. This could be the case in future at Fingrid if MPLS network replaces current SDH network.

Traveling wave fault locator can locate the fault with ±300m error margin with 1 μs accuracy. Better synchronization accuracy leads to better fault location estimation which is typically better. TWFL uses GPS receiver to reach synchronization. Fingrid uses a method that requires synchronization between two TWFLs. TWFL is not a critical application but competent fault location estimation saves time and money when the patrol group is sent to correct place for fault investigation. Another time distribution method than GPS could be beneficial with better reliability and accuracy not worse than 1 μs.

The amount of applications that uses accurate synchronous time could be higher if there was a reliable synchronized time source for each substation. Current situation does not offer an environment where time critical applications can develop. This situation means GPS is the only accurate time distribution method and it cannot be trusted. It would be beneficial for the current applications and for their users if every substation would receive time synchronization reliably within 1 μs accuracy. Because of historical development and different time synchronization requirements for different applications, we have a diverse time distribution installations consisting of GPS receivers, NTP time and SCADA time. Standardizing time distribution between the substations and inside the substation would be beneficial for Fingrid.

4.2 Possible scenarios for time distribution at Fingrid power system

This subsection discusses different scenarios and possibilities for Time of Day synchronization for Fingrid. There are two main scenarios for Fingrid depending whether MPLS network will replace PDH and SDH network in the future. Additionally the case where no actions are done to improve time synchronization is considered. The costs of different options is out of the scope.

4.2.1 If MPLS does not replace SDH and PDH technology

This scenario is possible if Fingrid will keep the SDH network and the next generation telecommunication network is postponed. This scenario includes following options for time distribution: PTPv2, GNSS, NTP, and no actions.

PTPv2 over existing MPLS network

PTPv2 is a time distribution method for Ethernet based network and it enables time distribution within 1 μs accuracy. Fingrid already has an MPLS network connecting every substation. This existing MPLS network is run over current SDH network. However, if PTPv2 would be implemented straight to the existing MPLS network, it would probably not reach to the target accuracy.

PTPv2 implementation to current MPLS routers and switches would require at least a software update. Hardware update for time stamping method would be required to reach full accuracy. There may also be non-PTPv2 devices between the PTPv2 routes, which will degrade the synchronization accuracy. In addition it would require hardware changes if SyncE would be implemented together with PTPv2. Upgrading existing MPLS network to PTPv2 and SnycE could be an expensive solution and still there is no guarantee to reach 1 μs accuracy because there may be non-PTPv2 devices along PTPv2 path.

GNSS

GNSS is the most accurate time distribution method on the market. GPS provides time with 50 ns accuracy. There are no extra nodes to degrade time accuracy between the atomic clock inside the satellite and the receiver at the substation. Fingrid already has GPS receivers almost at every substation. It is only a question how distribution of GNSS time would be distributed inside the substation for the applications. GNSS would be an effective method, since it is the most accurate and does not require any designing process for terrestrial time synchronization.

The lack of trust in GNSS signal is a major problem. Especially if there are system critical applications leaning on GNSS synchronization. Disturbing one receiver could lead to errors in the power system. For this reason, there should be countermeasures against GNSS disturbance and spoofing. The most important aspect is monitoring GNSS signals metrics in real-time. If it is possible to notice when timing is unreliable, it is possible to take counteractions. If a GNSS receiver fails to deliver time there could be following countermeasures:

- Change between different GNSS: GPS, Galileo, GLONASS or BeiDou. This should be done at each substation in order to have the same source for each substation.
- If there is a secondary time source such as a Rubidium oscillator at the substation, it could be used instead until GNSS works again.
- Let this substation drift in time and shut down all time dependent applications. E.g. Line differential protection falls back to echo mode.
- Fall back to SCADA time as the system works today.

Additionally GNSS usually offers an encrypted signal, which will be more difficult to spoof. However, there is an additional cost compared to free non-encrypted signal. There are commercial GPS firewalls or software that identifies and protects GPS systems from jamming and spoofing, such as Microsemi BlueSky and Spectracom/Talen-X SecureSync.

All these commercial countermeasures and possibilities to change between different GNSS, may be expensive to implement for every substation. Thus, if protection against spoofing and jamming is required, it is possible that terrestrial time synchronization will be a financially competitive solution.

NTP over existing MPLS network

NTP over existing MPLS network has already been tested for few Fault recorders with good results. NTP offers time synchronization with 1 ms time accuracy. This would be still an improvement to SCADA time where time accuracy can be hundreds of milliseconds. It cannot offer time to e.g. TWFL or PMU, but it can offer time for fault recorders and relays. (LDP would still rely on echo method, but the event log could be NTP time.)

No new actions for time distribution

Transmission reliability of Fingrid's grid was 99,9998% in 2016. Thus, there is not much to improve in transmission reliability point of view. This aspect does not motivate to invest in time distribution technologies. Still there are a few reasons why time synchronization should be improved:

- The change of production structure from conventional power plants to distributed energy sources may add fluctuations to power balance and result to faults. It is possible that in the future we have a greater need for time dependent information such as real-time voltage phase angles from system nodes and fault data from sequential events.
- Digital substation and IEC 61850 leans to Ethernet based communication, which enables NTP and PTP time distribution inside the substation. Digital substation and IEC61850 is seen as the future development in Fingrid. It will be wise to update time synchronization together with digital substation projects.
- Other Nordic TSOs are also investigating possibilities to upgrade their time distribution. Fingrid has the ambition to be the reference point of TSOs, thus they should also lead the way in time distribution or at least keep up with the neighbours.
- SDH technology is getting old and packet switched network technology is increasing. This encourages Fingrid to renew their network which could enable PTP implementation.

4.2.2 If MPLS replaces SDH and PDH technology

This scenario is possible if MPLS proves to be a reliable alternative for SDH. Replacing SDH will take years. This scenario includes following options: PTPv2, PTPv3 and GNSS.

PTPv2

PTPv2 requires a proper platform to reach its full 1 μs accuracy. In greenfield MPLS acquisition the network can be designed to be optimal for PTPv2. Optimal means that there will be no non-PTP devices, not too many PTP nodes between the time source and applications, and the PTP devices supports hardware time stamping, suitable PTP-profiles and SyncE. Native PTPv2 would be the best option to match Fingrid's needs. It offers exactly the accuracy what Fingrid requires and takes advantage of Fingrid's terrestrial optical fiber network.

PTPv3

PTPv3 also known as White Rabbit or High accuracy profile is the new version of PTP which will be published in 2018. Norwegian Transmission System Operator (TSO) Statnett has together with VTT Mikes and Justervesenet a time distribution project where they will test PTPv3 for Statnett substations.

Fingrid could also participate the same project. However, for Fingrid at the moment PTPv3 technology is not mature enough for an telecommunication equipment acquisition which is happening currently. It differs from Statnett situation, because Statnett is focusing on new time distribution, whereas Fingrid is planning to fully renew the telecommunication equipment and time distribution can be included as a "side product". Still, it should be seen as an future option to implement PTPv3. The router and switch manufacturers may start to offer commercial PTPv3 products only after the standard is available and there is existing demand from customers. So far PTPv3 device manufacturing is more R&D based. It is possible that PTPv2 can be later upgraded with software update and/or minor hardware changes, but this is speculative at the time of writing.

PTPv3 offers 1 ns accuracy which is better compared to PTPv2 1 μs accuracy. On the other hand, only TWFL would benefit from PTPv3 accuracy. Additionally, mature PTPv2 technology is most probably more cost efficient than immature PTPv3 technology. In Fingrid, it is difficult to justify more expensive solutions unless it improves transmission reliability, which is already high.

GNSS

In the case where the new MPLS network is implemented, but PTPv2 does not work as well as it should, GNSS would be a valid alternative option for time distribution. It has proper accuracy and it's relatively easy to deploy. Obviously, the security issue should be handled as discussed in section 4.2.1. Alternatively, it is possible to use GNSS as a backup time distribution method in case PTPv2 fails or vice versa.

4.3 Time distribution from time source to the applications in Fingrid power system

This subsection presents an option for the time distribution from time source to the applications. First, we go through the current situation to clarify the difference of the possible new implementation.

4.3.1 Current situation

Fingrid has more than one hundred substations. They are built in different times and for different purposes. For that reasons there are various different kinds of installations. Figure 20 presents a possible time distribution topology from current system.

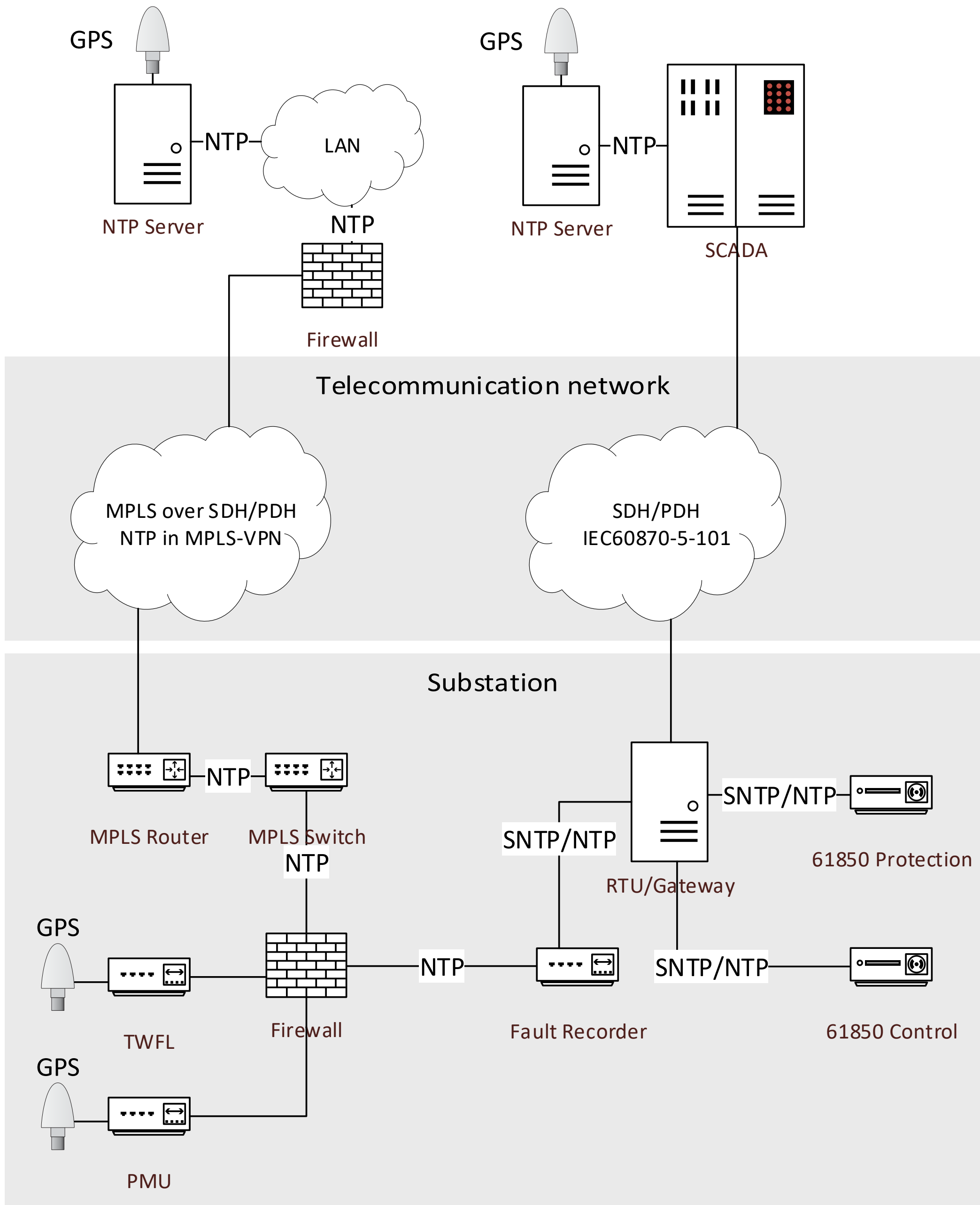


Figure 20: Example of a possible time distribution path from current network

MPLS network is run over current SDH/PDH network. There are two different clouds, the first representing MPLS network and the second representing SDH/PDH network. Regardless the networks are presented in different clouds, physically they may run over same cables and telecommunication devices.

The Figure only presents paths and devices that are meaningful for time synchronization. Routers, switches and SDH/PDH equipment forwards time information from the time sources to the end devices. Telecommunication network contains two clouds. The clouds represents telecommunication equipment that locates on different substations. Routers and SDH/PDH equipment are interfaces between the network and substation LAN.

It could be possible to run PTPv2 over the current MPLS network. However, there would be too many non-PTP devices along the path and thus PTPv2 would not offer much better accuracy than NTP. Current GPS source for time distribution itself is accurate enough for any end application. NTP over MPLS and IEC 60870-5-101 over SDH/PDH decreases the accuracy down to milliseconds or worse. IEC 60870-5-101 is the protocol that distributes time for SCADA. Because of insufficient time accuracy, PMU and TWFL requires their own local GPS receivers to function properly.

The drawbacks of current situation are:

- Telecommunication network does not offer accurate time.
- PMUs and TWFLs are dependent on GPS and they both require their own GPS instead of sharing one.
- Time distribution that telecommunication network offers is dependent on SDH/PDH technology which is an a slowly vanishing technology.

The upside of the current situation is, that the system is familiar and Fingrid personnel knows how to run the system. The operational security of the Fingrid power system is excellent, thus the telecommunication network must be practical enough for its purpose. On the other hand, there are differences in the installations and it would be easier to operate the system if there were a standard time distribution installation at every substation.

4.3.2 Future implementation

Future implementation assumes that Fingrid has a new MPLS network with native PTPv2. PTPv2 time is now distributed to every substation by the already existing fiber connections between the substations. Time source for PTPv2 comes as a service from VTT MIKES and the secondary source is GNSS. It should be noted that the MPLS network covers only the WAN network between the substations. The substation LAN may have another packet-switched network protocol such as Ethernet. MPLS Routers forms the main frame of WAN and acts as an interface between WAN and substation LAN.

Figure 21 illustrates the topology of time distribution from time source through telecommunication network and finally to end applications. Only meaningful network devices that affects significantly to time accuracy are presented. Additionally WDM

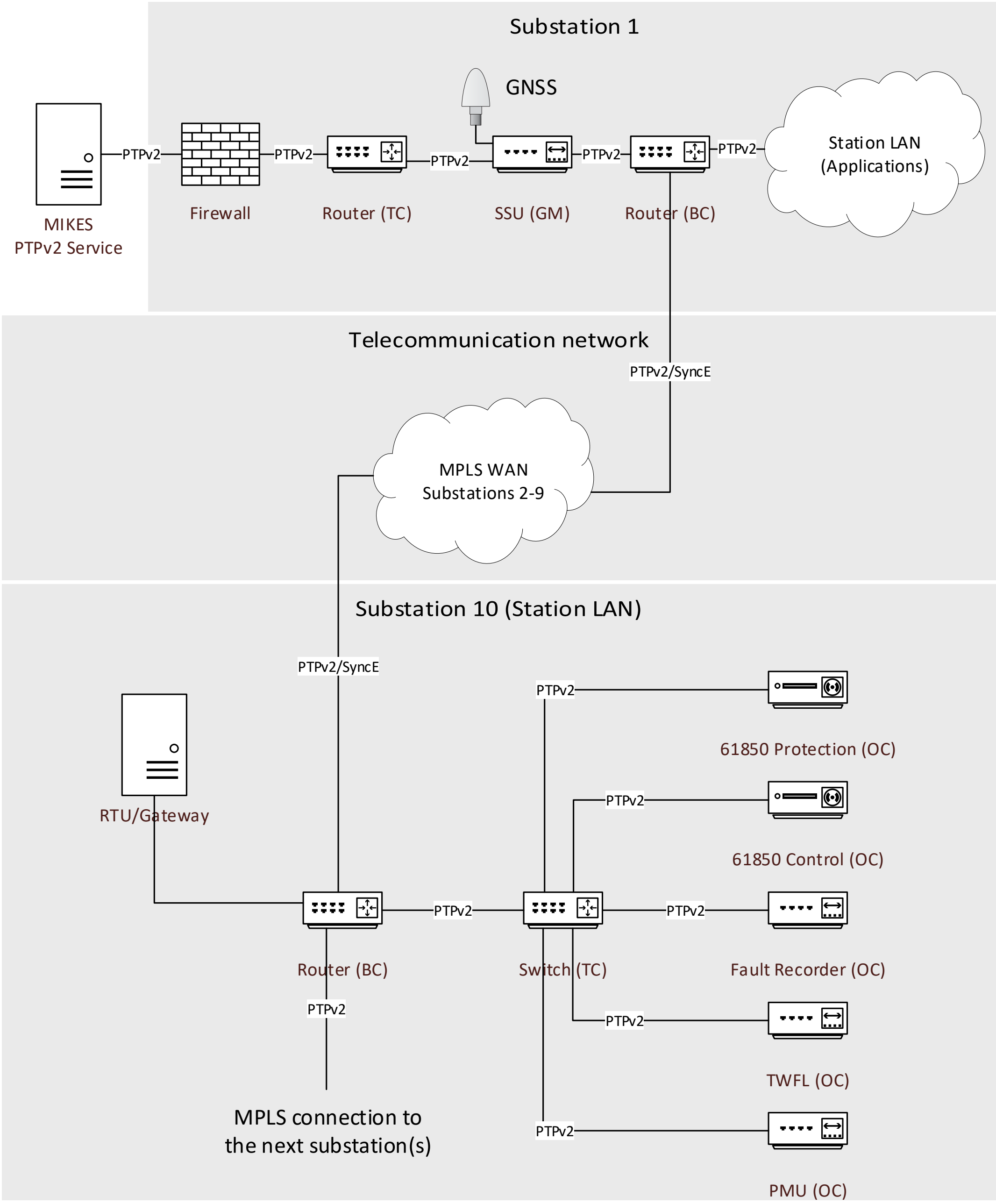


Figure 21: Future scenario of time distribution

(Wavelength Division Multiplexing) devices would matter if the time distribution method were more accurate such as PTPv3. Each PTP device causes a certain time error that has to be calculated into time error budget. In the Figure 21 Firewall is excluded from time error budget. Though it is likely that it causes time error and would affect to the time error budget. It can be taken into account in future budgeting when the impact is known. Note that the Routers in the Figure 21 does not belong to station LAN even it locates there in the Figure. Routers acts interfaces between the WAN and substation LAN.

The MIKES PTPv2 Service represents the time source for PTPv2. The source from MIKES makes the whole Power grid independent from GPS, which is one of the goals of terrestrial time distribution. MIKES should be able to offer their PTPv2 time at least from two different places in Finland. The Fingrid telecommunication network with only one time source would cause too long time chains with too many nodes to distribute time with accuracy better than 1 μs. Each node degrades time accuracy. The original PTPv2 BMCA allows only one active master clock (time source). In this case, with two or more MIKES time sources, Fingrid should either differentiate PTPv2 areas with each having only one connection to MIKES time source, or use alternative BMCA which allows multiple simultaneously active master clocks.

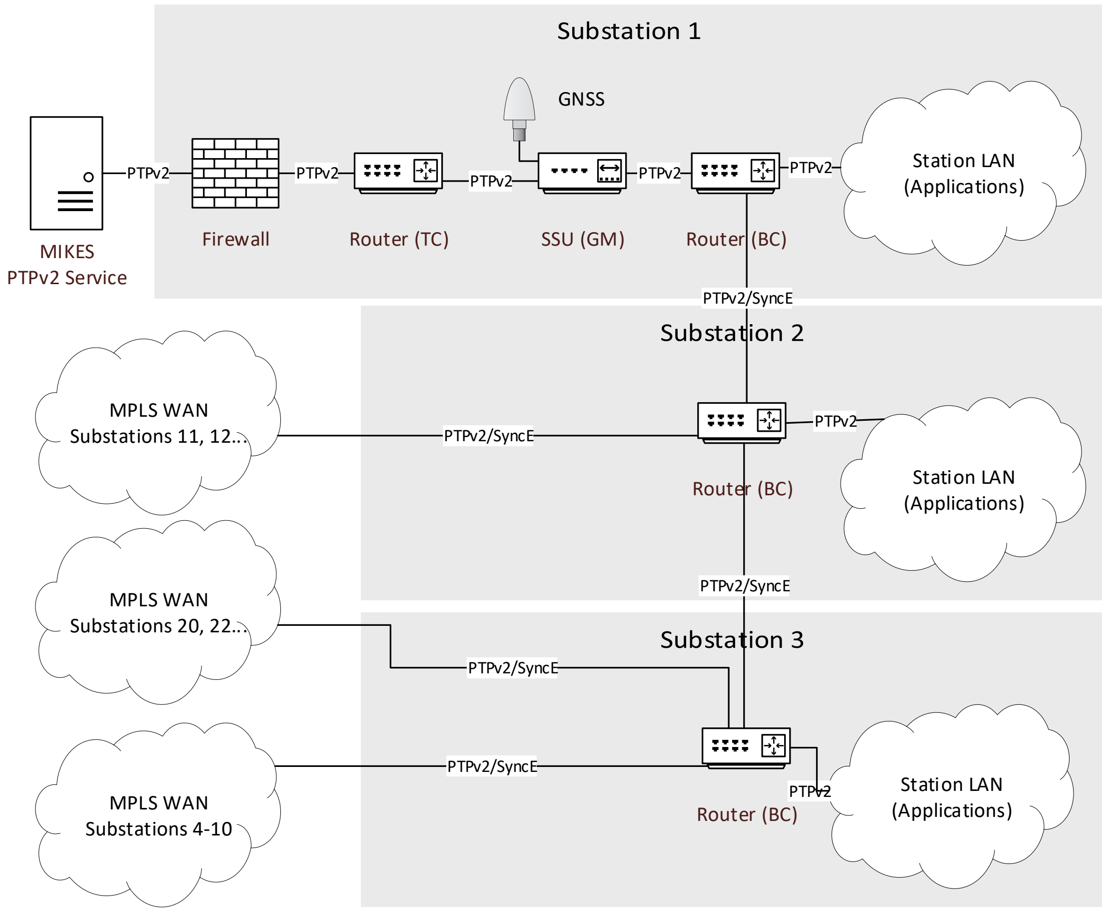


Figure 22: Future scenario of time distribution: MPLS WAN tree structure

The MPLS WAN cloud in Figure 21 can additionally contain more substations than it states (Substations 2-9). The WAN may be mesh or tree structured where also PTPv2 messages are forwarded to multiple other substations. In here, we concentrate to how many substations the PTPv2 can bypass while maintaining the accuracy in allowed limits. This estimation can be used when Fingrid designs their PTPv2 network topology. Figure 22 illustrates possible tree structure of PTPv2 WAN. The default BMCA of PTPv2 allows only tree topology and avoids timing loops that are possible with meshed topology.

Redundancy

Redundancy in PTPv2 becomes from PTPv2 capability to change source for master clock signal in case of there is no PTPv2 signal from upstream. The basic idea in Figure 21 and 22 is that each substation has at least one Boundary Clock (BC) that has sufficient holdover capabilities. Sufficient holdover capability can be acquired e.g. with Rubidium clock. Thus, the WAN network consists of boundary clocks that each can maintain accurate time even if the PTPv2 signal from Substation 1 is lost.

Figure 23 proposes a more redundant solution where each substation additionally has their own local GNSS receiver. It allows more redundancy schemes to be designed. Optionally each local GNSS can serve as the first time source for their local substation LAN and PTPv2 time from WAN/MIKES will be a secondary source. In this scenario PTPv2 WAN will suffer by having one extra node along the time path compared to Figure 21. The Synchronization platform can be a SSU or other PTP device that is able to generate PTPv2 time from GNSS source and make a reasonable decision whether to forward PTPv2 time from GNSS source or from WAN. In practice, the Synchronization platform has to be a BC in order to generate PTPv2 time from GNSS, since TC only forwards PTP messages.

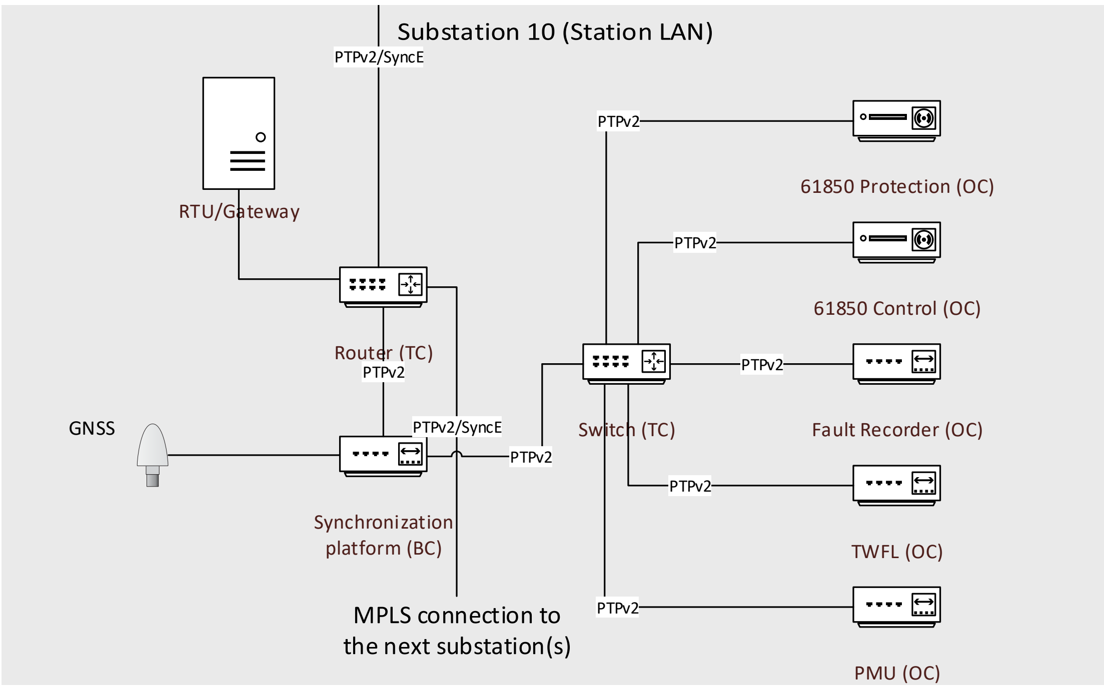


Figure 23: Future scenario of time distribution with local station GNSS

Now if The Synchronization platforms at every substation are BCs and they additionally have holdover capability, there is no need for the MPLS WAN routers to be BCs. Thus in the Figure 23 the router is a TC.

Time error budget

Figure 24 presents the time error budget from MIKES time source to the applications that locate on 10th substation. The number behind each node name represents the number of the substation where the node is. As it can be seen, with this TE budget estimation, it is possible to distribute PTPv2 time through 10 substation and remain within 1 μs accuracy limit.

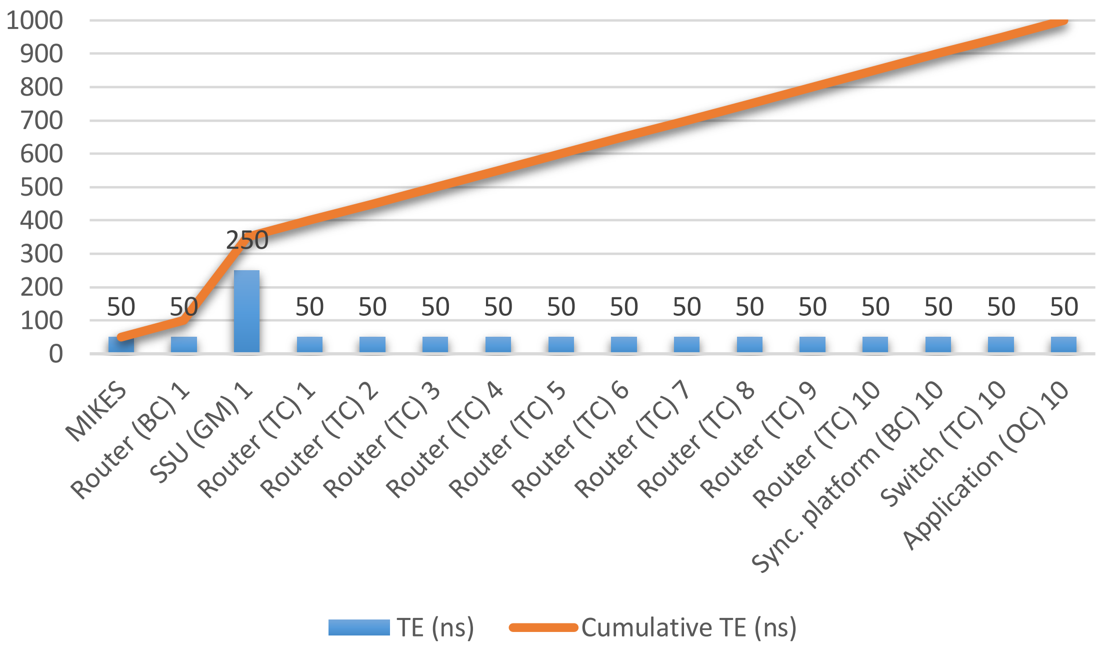


Figure 24: Time Error Budget for PTPv2 time distribution from time source to the applications.

One major uncertainty comes from estimating the time error introduced by each node. It is the device supplier who promises their equipment to keep within certain limits and the real TE input has to be field tested against reference time. The Power Utility Profile (PUP) requires 50 ns accuracy for a TC and ±200 ns accuracy for BC. However, e.g. in [39] it is tested that their TC and BC in laboratory conditions introduces a ±25 and ±30 ns time error respectively. Thus in here we estimate a BC and TC to both have 50 ns time error. The SSU in Figure 24 has 250 ns time error, which is taken from the PUP. However, G.8271.1 for mobile base stations says that PRTC/T-GM allows ±100 ns time error. This can be seen from Figure 6.

If BC introduces ±200 ns time error, it is not possible to use BC tree topology for MPLS WAN, since then already five BCs fills the 1 μs TE budget. In that case the MPLS WAN should be built of TCs instead of BCs as in Figure 23. In the network introduced in the Figure 21 and 22, optionally the WAN Router should be a TC and the LAN Switch should be a BC with holdover capabilities. If BC introduces ±200 ns time error and SSU ±250 ns time error it will allow only four substations in series with Figure 23 topology until the TE budget is full. Figure 25 illustrates a new TE budget estimation with ±200 ns error from a BC. Allowing only four substation in one PTPv2 branch is not an ideal situation for PTPv2 WAN design perspective. There are more than one hundred substations and only few places where MIKES can deliver their time.

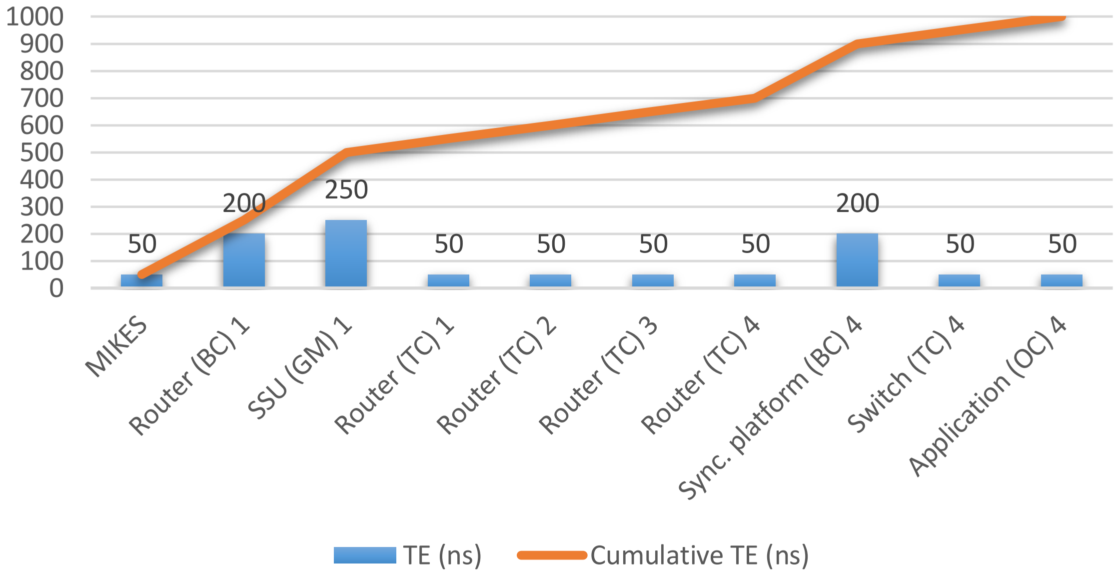


Figure 25: Time Error Budget for PTPv2 time distribution from time source to the applications in case a BC causes an error of ±200 ns.

Nevertheless, there are differences of time error estimations depending from the source. In practice, there will be a negotiation between Fingrid and the device supplier for how accurate the PTP devices will be and for what cost. This time error budget estimation presents a basic idea for future budgeting.

Additionally, it should be noted that in above example with 10 substations the worst-case scenario can cause an absolute time error of 2 μs between two devices on different substations. 2 μs error is possible if there are two substations, both 10th from the time source, their PTPv2 branches differentiates from the beginning, and in each node there are maximum time error to opposite direction. This is possible because time error estimation is presented by a possibility of same sized positive and negative error (±). This maximum absolute time difference is in allowed limits since the desired accuracy level Fingrid applications requires is ±1 μs.

Even if the ±1 μs TE is exceeded along PTPv2 time distribution, only TWFL performance decreases. The next application that suffers is line differential protection (LDF) and PMU in ±10 μs level. If PTPv2 time distribution exceeds that level in real life implementation, it leads to GNSS receiver installations for PMUs, TWFLs and forces LDF to use echo delay measurement method. One of the most important aspects for PTPv2 WAN distribution with MIKES time source is to remove the GPS dependency. And if that does not happen, it should be considered again whether PTPv2 is the correct method to distribute time in WAN.

PTP Profiles

From perspective of designing the PTPv2 network, and MPLS network device acquisition, it is important to understand which profiles the devices should support. The main 1588 PTPv2 standard leaves room for different kinds of configurations. The PTP profiles are customized for certain domains and add more functionalities or restrictions on top of the default profile.

The Power profile and Power Utility profile should be included to both WAN and LAN. These profiles are designed for power system protection, control and automation. Power Profile is compliant with PUP and extends it with continuous monitoring of time inaccuracy. PUP provides time accuracy requirement parameters for different PTPv2 devices. Both profiles are meant for LAN and WAN.

Monitoring can be done for both WAN and LAN if the Power Profile includes both of them. Monitoring is important for Fingrid in order to know whether the PTPv2 time distribution is accurate enough for any moment. If applications are aware of the time accuracy they receive, they can either change their time source if possible or send an error message to the users if necessary.

Power profile introduces redundancy by allowing multiple GMs and diverse network paths. Also RSTP, PRP and HSR redundancy protocols are compliant with Power Profile, though it should be noted that at least HSR is meant only for Ethernet substation LAN. Power Profile and PUP itself is based on Ethernet L2 communication. MPLS is not Ethernet, but it is possible to distribute Ethernet frames between MPLS routers or over L2-VPN. This has to be taken into account during the design phase of MPLS WAN.

If Power profile and PUP are not applicable for MPLS WAN, it is possible to use different profiles for LAN and WAN. Boundary clocks are able to translate between different PTP profiles. Telecom profile G.8275.1 can be used for WAN as [30] proposes and Power profile including PUP for LAN. Telecom profile uses Ethernet multicast addressing for the transmission of all PTP messages. Thus, if Telecom profile is deployed, Ethernet multicast needs to be enabled in the MPLS network.

4.4 Requirements for device acquisition

One purpose of this thesis was to provide a list of aspects what should be taken into account in telecommunication device acquisition and designing the time distribution. The ongoing procurement concerns mostly WAN equipment but time distribution must be discussed as a whole including LAN and the end applications. This subsection lists all major aspects that should be discussed during the acquisition of WAN equipment and design of time distribution. The following aspects should be considered for each device (such as router, switch, SSU and end application) that belongs to PTPv2 time distribution path:

- Support for PTPv2 time distribution. PTPv2 is the most promising and sufficient time distribution method for Fingrid needs. All the devices along the time distribution path must be PTPv2 compliant in order to reach full accuracy.
- Devices must support PTPv2 hardware time stamping and TCs are P2P capable in order to reach full accuracy.
- Possibility to upgrade PTPv2 to PTPv3. This should be at least discussed whether it is possible with minor software and hardware changes. Upgrade may be needed in case PTPv2 will not reach to its full accuracy and it is seen that PTPv3 would improve the time distribution accuracy.
- SyncE improves frequency synchronization. It offers better conditions for PTPv2 time of day synchronization. Using PTPv2 alone, time of day synchronization could take hours and more depending on how many PTPv2 nodes there are in series.
- PTP profiles should be decided. E.g. Power Utility profile is meant for power utility automation and Power profile extends it with continuous monitoring of time inaccuracy. In device acquisition, it is possible to demand routers to support certain profile.
- Requirements for time error introduced by different type of PTPv2 clocks (BC, TC, GM) must be known in order to calculate time error budget. After TE effect of each type of node is known, it is possible to design PTPv2 WAN network to fulfil the accuracy requirements.
- PTPv2 performance has to be monitored. With monitoring, it is possible to know if there are substations and applications that receive inaccurate time. After that it possible to execute redundancy schemes.
- Redundancy schemes must decided. If there are multiple simultaneously active grand master clocks, there has to be an alternative BMCA that each PTPv2 device executes.
- Holdover capability to boundary clocks has to be defined. If Fingrid requires long and accurate holdover it means that BCs include quality oscillators. Holdover is important when WAN fails to deliver PTPv2 time and substation still needs accurate time for its applications. Holdover provides time to solve the time distribution issue without interrupting the functionalities of applications.

4.5 Significance for transmission reliability

Transmission System Operator in Finland is responsible of securing reliable electricity for the society. Transmission reliability or operational security are measures that illustrates how well Fingrid is fulfilling its purpose. That should be kept in mind in every project at Fingrid. Does the investment in improving time distribution serve Fingrid's main mission?

Time distribution provides accurate and synchronous time for the substation applications. Substation applications are significant for transmission reliability. Some of them directly and other indirectly. Time distribution significance for transmission reliability should be viewed from application point of view. What contribution more accurate and reliable time distribution has for applications, and through that to transmission reliability, is one approach. Next, we will go through all the four applications one by one and debate whether new PTPv2 improves transmission reliability through them.

PMUs have already accurate enough time from GPS. New PTPv2 time distribution would only increase reliability. At the moment PMU information is used for niche information for post analysis. Reliable and accurate time for PMUs could improve PMU information adoption to real-time operative use. PMUs offer valuable voltage angle information that current SCADA does not offer. Transmission reliability is difficult to improve, since it is already extremely high in Fingrid (99,9998%). However, PMUs could help operators to notice and understand better threatening situations. E.g. [40] says that the North American blackout in 2003 could have been prevented with real-time phase information from PMUs.

Fault Recording aims to one millisecond accuracy. Currently there are tens and hundreds of millisecond synchronization errors between different fault recorders and substation relays. Relay collects similar information as Fault recorders thus it would be useful if they would be synchronized to millisecond accuracy. If Fault recorder receives time from MPLS NTP server, then the Fault recorder itself has sufficient time, but it does not help when relay information is compared. Thus, it would be beneficial to have common accurate PTPv2 time source for Fault recorders and relays. In this case, the transmission reliability improves through faster fault analysis, which can lead to faster actions to repair the fault and saves the time of employees. Most of the minor fault situations do not require synchronized information from multiple nodes, and for these the current accuracy level is enough. However, in large fault situation proper synchronization is valuable.

Line Differential Protection is an application that affects most directly to transmission reliability, because it is responsible opening the circuit in fault situations and prevent further damage. Now LDF uses echo method for its synchronization, thus it does not need time of day synchronization. PTPv2 could offer more precision to the synchronization compared to the current echo method. Then LDF could be configured to use more sensitive settings and would detect certain high resistance faults better than before. From this aspect, PTPv2 improves transmission reliability. However it requires that LDF would trust to PTPv2 first and the asymmetrical synchronization method would be secondary option.

Travelling wave fault locator detects the fault location from the transmission line. PTPv2 would not improve the accuracy of TWFL since it uses at the moment more precise GPS time. However, PTPv2 would offer an option to be independent from GPS time with accuracy that would still be reasonable for fault detection.

5 Summary

5.1 Conclusions

The purpose of this thesis was to answer the questions: "How accurate time Fingrid requires?" and "What is the most suitable method to distribute accurate and reliable time to Fingrid substations?" The thesis was written because Fingrid Telecommunication department is planning to renew their telecommunication equipment and at the same time it would be possible to offer time distribution as a service through the telecommunication network.

There are only a few different ways to deliver accurate and synchronous time to electrical substations. PPS does not include time of day synchronization, IRIG-B requires dedicated cabling and is suited better for LAN purposes and NTP does not improve much current situation. GNSS offers the best accuracy and does not require terrestrial time distribution, but it is not secure without additional measures against jamming and spoofing. PTPv2 is the most suitable for Fingrid purposes. It takes advantage of Fingrid's existing fiber network, makes Fingrid independent from GPS, it is a mature technology and is accurate enough.

PTPv2 requires a time source. There are three options: MIKES time service, GNSS, or own atomic clocks. In reliability point of view, an ideal option is to have all three of them. Fingrid could buy three atomic clocks and let MIKES steer them to match the national UTC time. GNSS could serve as a backup source in case the first one fails. GNSS is more accurate than PTPv2, thus alternatively it can be the first option and PTPv2 the second one.

Fingrid has currently four applications that requires synchronization: Phasor Measurement Units, Fault Recorders, Line Differential Protection and Traveling Wave Fault Locators. The target accuracy level for PTPv2 to serve these applications is 1 μs. Though it should be noted that there are differences between the time accuracy requirement for each application and none of these applications fails immediately if 1 μs accuracy is slightly exceeded. From the application point of view, the reliability is as important as the accuracy. Secure and seamless time distribution is possible to design with PTPv2. Secure and accurate time distribution creates an environment where more time dependent applications can develop.

There is a progress towards more decentralized power production, which causes more fluctuations to power balance. Accurate and reliable time distribution offers tools to be more aware of the system state than currently it is possible and enables fast recovery. Today the transmission reliability is more than good and there is no room to improve it. However, if Fingrid wants to maintain the transmission reliability in the future, it has to improve its infrastructure to match tomorrow's challenges.

It would be a wise decision from Fingrid to upgrade their time distribution. There is a great opportunity to include the time distribution upgrade with the next generation telecommunication network project. Fingrid would not be the only one to invest to accurate time synchronization. Norway's TSO has already started the implementation of PTP time distribution in their network. Fingrid wants to be the reference company among Transmission System Operators around the world. It requires improving and updating the current infrastructure and its functionalities. Improving time distribution serves that goal.

5.2 Further work

Next step towards accurate and synchronous time at Fingrid substations would be setting up a laboratory test network for PTPv2. If the laboratory tests are promising, proof of concept network can be built for existing substations. At these substations, some or all applications would rely on PTPv2 time. If the proof of concept network demonstrates competent results, Fingrid can implement PTPv2 to the rest of the network. It should be noted that PTPv2 implementation would be initially dependent to the renewal project of the whole telecommunication network.

Negotiation with MIKES should be started for time service. Cost analysis for acquiring own atomic clocks should be reflected to the benefits. Continuous monitoring and automated redundancy schemes needs further study. It is unclear how well in reality the PTP devices will be able to monitor their time distribution performance and react to degradation of time accuracy.

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